Preliminary Draft
Regulatory Impact Analysis

Proposed Stream Protection Rule

NOTE: THIS WORKING DRAFT OF THE RIA CONTAINS NUMEROUS PLACEHOLDERS SINCE THIS CONTENT WILL BE DEVELOPED IN THE FUTURE IN LINE WITH THE WORK PLAN GROWING OUT OF RECENT OSM DIRECTION AND THE PKS TEAM'S RESPONSE TO THE CURE NOTICE ISSUED BY OSM ON FEBRUARY 8, 2011.

Prepared for:

U.S. Department of the Interior
Office of Surface Mining Reclamation and Enforcement

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List of Acronyms and Abbreviations

Acronym or Abbreviation	Definition
AC	Avoided cost
AEO	Annual Energy Outlook
AML	Abandoned Mine Land
ANPR	Advance Notice of Proposed Rulemaking
AOC	Approximate Original Contour
BCA	Benefit-Cost Analysis
BEA	Bureau of Economic Analysis
BET	benefit estimate transfer
BLS	Bureau of Labor Statistics
BT	Benefit transfer
Btu	British Thermal Unit
CAA	Clean Air Act
CBA	cost-benefit analysis
CBM	Coalbed Methane
CEA	Cost-Effectiveness Analysis
CFR	Code of Federal Regulations
CMM	Coal Market Module
CO_2	Carbon dioxide
CTL	Coal-to-liquids
CRP	Conservation Reserve Program
CV	Contingent valuation
CWA	Clean Water Act
DOI	Department of Interior
EBITDA	Earnings Before Interest Expense, Income Tax Due, Depreciation, and Amortization
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
FGD	Flue Gas Desulfurization
FY	Fiscal year
GDP	Gross Domestic Product
GHG	Greenhouse Gas
Hg	mercury
HP	Hedonic pricing
IAP	Interagency Action Plan
ICG	International Coal Group Inc.
IMPLAN	Impact Analysis for Planning
kW-h	Kilowatt Hour
MAM	Macroeconomic Activity Module

Acronym or Abbreviation	Definition
MMBtu	Million British Thermal Unit
MOU	Memorandum of Understanding
MSHA	Mine Safety and Health Administration
MW	Megawatt
NAICS	North American Industry Classification Code System
NEMS	National Energy Modeling System
NMA	National Mining Association
NWP 21	Nationwide Permit 21
OMB	Office of Management and Budget
OSM	Office of Surface Mining Reclamation and Enforcement
PCT	preference calibration transfer
PF	Production function analysis
PPI	Producer Price Index
PRB	Powder River Basin
RC	Replacement or Restoration cost
RFA	Regulatory Flexibility Act
RIA	Regulatory Impact Analysis
SBA	Small Business Administration
SBZ	Stream Buffer Zone
SIC	Standard Industrial Classification
SMCRA	Surface Mining Control and Reclamation Act of 1977
SPR	Stream Protection Rule
SRA	state regulatory authority
STB	Surface Transportation Board
TC	Travel cost
USCB	U.S. Census Bureau
USDOL	U.S. Department of Labor
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
WTA	willingness-to-accept
WTP	willingness-to-pay
WVDEP	West Virginia Department of Environmental Protection

Abstract

This document presents the results of a regulatory impact analysis (RIA) of the Office of Surface Mining Reclamation and Enforcement's (OSM's) proposed new stream protection rule (SPR), which will apply to coal-mining activities across the United States.

The document responds with best available information to the regulatory impact analysis guidance provided by the U.S. Office of Management and Budget (OMB). In this regard, this document:

1. Identifies the major elements of the proposed SPR.
2. Describes the rationale and need for the new rule.
3. Discusses the regulatory baseline for the rule.
4. Discusses alternative regulatory approaches to the rule.
5. Provides an economic justification for the rule.
6. Describes the methodology, major data sources, and assumptions used in preparing the RIA.
7. Identifies the major economic benefits, costs, and transfers associated with the rule with quantification and monetization of these benefits and costs where possible.
8. Identifies possible impacts of the rule on small business entities, as required under the Regulatory Flexibility Act (RFA).
9. Provides an overall summary of the rule's estimated benefits and costs and the net benefit (or cost) of the rule.
10. Provides references and supporting data and analysis supporting the RIA.

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1 Introduction and Purpose

1.1 INTRODUCTION

The purpose of this document is to present the results of a Regulatory Impact Analysis (RIA) of the economic costs and benefits of the Office of Surface Mining Reclamation and Enforcement's (OSM's) proposed Stream Protection Rule (SPR). This RIA is conceptual in nature because it relates to the proposed SPR, which represents a working concept of what the final SPR might look like.

By definition, an RIA is *"a tool regulatory agencies use to anticipate and evaluate the likely consequences of rules. It provides a formal way of organizing the evidence on the key effects−good and bad−of the various alternatives that should be considered in developing regulations."*[1]

The RIA is required for three reasons:

1. Provide an improved overall economic basis for the regulatory policy decisions made during the SPR rule-making process.
2. Identify major economic issues raised by the proposed SPR that may have significant consequences for the national economy, the coal-mining industry, and coal-producing areas.
3. Explore and discuss the significance of these major economic issues in a way that helps policy decision-makers address them and resolve them where possible.

The Surface Mining Control and Reclamation Act (SMCRA) aims to balance the need to protect the environment from the adverse effects of surface coal mining with the nation's need for coal as an essential energy source. The law ensures that coal-mining activities are conducted in an environmentally responsible manner, and that mined land is adequately reclaimed during and following the mining process.

This regulatory balancing act is not easy, and it must ensure that the nation's future coal needs can be met in an environmentally protective manner. According to the U.S. Energy Information Administration (EIA), as U.S. coal use grows in the 2011 Reference case forecast, domestic coal production increases at an average rate of 0.7 percent per year, from 21.6 quadrillion British Thermal Unit (Btu) (1,075 million short tons) in 2009 to 25.8 quadrillion Btu (1,305 million short tons) in 2035.

According to EIA's 2011 forecast report, coal production from mines west of the Mississippi River trends upward over the entire projection period. Following a substantial decline in output between 2009 and 2015, coal production east of the Mississippi River remains relatively constant from 2015 through 2035. On a Btu basis, 60 percent of domestic coal production originates from States west of the Mississippi River in 2035, up from 50 percent in 2009.

[1] U.S. Office of Management and Budget, Office of the President, 2003. Circular A-4, September 7, 2003, page 2.

This expected future growth rate is down somewhat from the actual annual growth of coal production of 0.9 percent during the 1980-2008 period. Several converging factors, including slower overall economic growth and increasing reliance on other energy sources, are expected to contribute to this slower growth rate of future coal production.[2]

Most coal-mining states now have the primary responsibility to regulate surface coal mining on lands within their jurisdiction, with the OSM performing an oversight role. OSM also partners with states and Indian tribes to regulate mining on federal lands, and to support states' regulatory programs with grants and technical assistance.

In April 2010, OSM published in the Federal Register a Notice of Intent to produce an Environmental Impact Statement (EIS) for the SPR, which will replace the 2008 Stream Buffer Zone Rule. The notice includes a list of concepts that are under consideration for the proposed SPR. Those concepts include provisions for coal-mining companies that elect to mine through or bury streams to gather more specific baseline data regarding a proposed mine site's hydrology, geology, and aquatic biology; establishing a definition of the term "material damage to the hydrologic balance" of watersheds outside the permit area; and developing more effective requirements for mine operators seeking a variance from the requirement that mined areas be reclaimed to their approximate original contour (AOC).

The concepts in the proposed SPR aim to offer a more systematic and comprehensive approach to protecting streams and the surrounding environment from the adverse effects of coal mining. OSM has reached out to possible impacted stakeholders to obtain their input on the SPR's draft elements, which are described immediately below.

A major purpose of the proposed federal action is to comprehensively revise permitting requirements and performance standards related to protection of the hydrologic balance, consistent with SMCRA, in order to better protect the environment and the public in all areas of the country from the impacts of surface coal mining operations on hydrology, stream biota, and related resources.

Further, a related purpose of the proposed federal action is to revise permitting requirements and performance standards to more effectively implement SMCRA section 515(b)(24) This section requires, subject to certain limitations, that surface coal mining and reclamation operations minimize disturbances and adverse impacts on fish, wildlife, and related environmental values, and also requires those operations to "achieve enhancement of such resources where practicable."

In addition, it is a purpose of the proposed federal action to encourage, and when appropriate, to require the use of the best science and technology available in regulating surface coal mining and reclamation operations and in conducting the operations.

Finally, it is a purpose of this proposed federal action to revise the relevant regulatory provisions consistent with all relevant requirements and purposes of SMCRA, including the purpose to "assure that the coal supply essential to the Nation's energy requirements, and to its economic and social well-being is provided and strike a balance between protection of the environment and

[2] U.S. Energy Information Administration, Annual Energy Outlook 2011, Early Release Overview, December 16, 2010.

agricultural productivity and the Nation's need for coal as an essential source of energy." Source: 30 U.S.C. 1202(f).

*Note: This RIA provides a net benefit (cost) analysis of the estimated economic benefits and costs of the proposed SPR***.**

1.2 NET BENEFIT/COST ANALYSIS PURPOSE

As a requirement of OSM's rule-making process, the RIA is intended to improve understanding of the potential economic impacts (costs and benefits) of the proposed SPR on the national economy, the coal-mining industry, and coal-producing geographic areas across the United States. *The RIA provides a net benefit/net cost assessment of these costs and benefits on the national level.*

An April 1, 2010, U.S. Environmental Protection Agency (USEPA) Guidance Memorandum on improving USEPA's review of Appalachian surface-mining operations lends support to OSM's new SPR nationwide. The memorandum states:

"The environmental legacy of mining operations in the Appalachian region is far-reaching. Recent studies, as well as the experiences of Appalachian coalfield communities, point to new environmental and health challenges from surface coal mining that we were largely unaware of even ten years ago. Since 1992, nearly 2,000 miles of Appalachian streams have been filled at a rate of 120 miles per year by surface mining practices. A recent USEPA study found that nine out of every 10 streams downstream of surface mining operations exhibit significant impacts to aquatic life. Another federal study found elevated levels of highly toxic and bioaccumulative selenium in streams downstream of valley fills. These impairments are linked to contamination of surface water supplies and resulting health concerns, as well as widespread impacts to stream life in downstream rivers and streams."

2 Necessity of the Stream Protection Rule and the RIA

2.1 MAJOR RULE ELEMENTS

In its Notices of Intent for SPR EIS, OSM identified eleven principal elements guiding its revision of various provisions of the SMCRA rules and regulations. It requested the public's comment on these elements and suggestions of other areas that should be addressed in order to protect streams from the adverse effects of surface coal mining operations nationwide.

The principal elements initially set forth include:

1. Stream Definitions. Each of below elements contributes to the protection of streams.
2. Definition of Material Damage to Hydrologic Balance
3. Corrective Action Thresholds
4. Collection of Baseline Data
5. Additional Monitoring Requirements
6. Mining Activities In or Near Streams
7. Mining Through Streams)
8. Surface Configuration and Fills
9. AOC Exceptions
10. Revegetation and Soil Management
11. Fish and Wildlife Protection and Enhancement
12. Miscellaneous Elements

2.1.1 New Regulatory Elements[3]

2.1.1.1 Stream Definitions.

- Revises perennial/intermittent/ephemeral stream definitions to include both physical and biological characteristics to improve ease and accuracy of classification. (§ 701.5)
- Eliminates that portion of the existing definition of an intermittent stream that includes any stream with a watershed greater than 1 square mile. (§ 701.5)

2.1.1.2 Definition of "material damage to the hydrologic balance outside the permit area."

- Defines material damage as any quantifiable adverse impact on the quality or quantity of surface water or groundwater, or on the biological condition of a perennial or intermittent stream, that would preclude any designated use under the Clean Water Act (CWA) or any existing or reasonably foreseeable use of surface water or groundwater outside the permit area. (§ 701.5)
- Clarifies that the impacts of subsidence resulting from underground mining and other impacts from underground mining activities are subject to the prohibition on material damage to the hydrologic balance outside the permit area. In practical terms, this means that the regulatory authority may not approve a permit for an underground mine if analyses indicate that the

[3] Source: OSM, February 3, 2011

proposed operation could result in subsidence or other impacts that would dewater or otherwise materially damage perennial or intermittent streams. [§ 701.5 (definition of material damage to the hydrologic balance outside the permit area)]

- Expands requirements for the determination of the probable hydrologic consequences of mining and the cumulative hydrologic impact assessment to ensure prevention of material damage to the hydrologic balance outside the permit area. (§§ 780.20, 780.21, 784.20, and 784.21)

2.1.1.3 Corrective Action Thresholds.

- Requires that the regulatory authority develop corrective action thresholds for parameters of concern. (§§ 780.21 and 784.21)
- Requires that the permittee conduct a quarterly review of monitoring data to determine whether corrective action thresholds are being approached. [§ 773.17(i)]

2.1.1.4 Baseline Data Collection and Analysis.

- Requires an accurate and complete analysis of surface water and groundwater that will allow better characterization of baseline conditions, provide a sound basis for material damage and cumulative hydrologic impact predictions, and identify high quality streams. (§§ 780.19 and 784.19)
- The parameters sampled must include a full suite of major cations and anions. (§§ 780.19 and 784.19)
- Includes language specifying the number, interval, and location of samples to be collected. (§§ 780.19 and 784.19)
- Requires baseline sampling of the biological condition of streams. (§§ 780.19 and 784.19)
- Emphasizes that baseline data collection requirements apply to areas overlying the underground workings. [§§ 701.5 (definition of adjacent area), 783.19, and 783.24]

2.1.1.5 Monitoring during Mining and Reclamation.

- Requires that water monitoring plans be adequate to evaluate the impacts of the mining operation on groundwater and surface water and to determine in a timely manner whether corrective action is needed to prevent material damage to the hydrologic balance outside the permit area. (§§ 780.23 and 784.23)
- Requires that water monitoring plans include a sufficient number of monitoring sites within the zone of potential influence of the operation to evaluate the accuracy of the findings in the determination of the probable hydrologic consequences of the operation and to provide timely detection and correction of any adverse trends. At a minimum, the plan must include

monitoring locations upgradient and downgradient of the operation. (§§ 780.23 and 784.23)

- Requires that groundwater monitoring plans include monitoring wells in any existing underground mine workings with direct hydrologic connections to the site of the proposed operation. (§§ 780.23 and 784.23)
- Requires monitoring of a full suite of major cations and anions plus any other parameters needed to reflect local conditions and CWA requirements. (§§ 780.23, 784.23, 816.35, 816.36, 817.35, and 817.36)
- Requires onsite monitoring of precipitation amounts using automatic recording devices. (§§ 780.23 and 784.23)
- For surface mines, requires that the groundwater monitoring plan include monitoring wells placed in the backfill. (§ 780.23)
- For underground mines, requires monitoring the elevation and quality of the underground mine pool after closure of the mine. (§§ 784.23 and 817.35)
- Emphasizes that monitoring requirements apply to areas overlying the underground workings. [§§ 701.5 (definition of adjacent area) and 784.35 through 784.37]
- Requires that surface-water and groundwater monitoring continue through final bond release and prohibits bond release until monitoring data indicate that there are no adverse hydrologic trends. (§§ 816.35, 816.36, 817.35, 817.36, 800.40, and 800.42)
- Requires monitoring of the biological condition of streams. (§§ 780.23, 784.23, 816.37, and 817.37)
- Requires that both the permittee and the regulatory authority review monitoring data to assess the accuracy of hydrologic impact predictions during the midterm review and permit renewal processes. (§§ 774.15, 780.20, 780.21, 784.20, and 784.21)

2.1.1.6 Activities In or Near Streams.

- Prohibits mining-related activities in or within 100 feet of perennial and intermittent streams unless the applicant demonstrates, and the regulatory authority finds, that the proposed activity would not (a) preclude any premining use or any designated use under the CWA of the affected stream segment following the completion of mining and reclamation, (b) have more than a de minimis impact on premining ecological function of the affected stream segment following the completion of mining and reclamation, (c) result in the conversion of the affected stream segment from intermittent to ephemeral or from perennial to either intermittent or ephemeral, and (d) cause or contribute to a violation of water quality standards. (§§ 780.28, 784.28, 816.57, and 817.57)

- Requires establishment of a 300-foot forested buffer on each side of the affected stream segment in previously forested areas or in areas that would revert to forest under natural succession, unless doing so is inconsistent with the postmining land use. (§§ 780.28 and 784.28)

- The above requirements do not apply to an excess spoil fill or coal mine waste disposal facility that would cover a perennial or intermittent stream segment. Instead, the applicant must demonstrate, and the regulatory authority must find, that (a) there is no reasonable alternative to constructing the fill or other facility in a stream, after considering all alternatives within one haul road mile of the permit boundary; (b) the alternative selected must minimize the length of stream filled and have the least adverse impact on fish, wildlife, and related environmental values; (c) the fish and wildlife enhancement plan would fully offset any adverse impacts that the fill or other facility would have on fish, wildlife, and related environmental values; (d) construction of the fill or other facility would not result in more than a de minimis adverse impact on the aquatic ecology of streams or other water bodies outside the permit area; (e) the fill or other facility would not cause or contribute to a violation of water quality standards; and (f) the revegetation plan requires that the fill be reforested if the land is forested at the time of application or if it would revert to forest under conditions of natural succession. (§§ 780.28 and 784.28)

2.1.1.7 Mining Through or Diverting Streams.

- Requires that the applicant demonstrate, and the regulatory authority find, that (a) there is no reasonable alternative that would avoid mining through or diverting the stream; (b) the operation has been designed to minimize the extent to which the stream will be mined through or diverted; and (c) the techniques in the reclamation plan will restore the physical form and ecological function of the affected stream segment, including recreating aquitards when necessary,

- Requires restoration of both the physical form and ecological function of all stream segments that are mined through or diverted, with adequate bond to ensure restoration. (§§ 780.28, 784.28, 816.57, and 817.57)

- Requires establishment of a 300-foot forested buffer on each side of a diverted or restored stream segment in previously forested areas or in areas that would revert to forest under natural succession. (§§ 780.28 and 784.28)

2.1.1.8 Surface Configuration and Fills.

- Incorporates the use of landforming principles into the definition of AOC and defines landforms and landforming. Landforms are the natural physical features that comprise the terrain in terms of elevation, slope, orientation, exposed rock, soil type, water features, surface drainage pattern, etc. Landforming is a design and grading technique that attempts to replicate the premining landforms by constructing slopes, drainageways, and other

landforms that blend in with the natural surroundings in an environmentally compatible fashion. (§ 701.5)

- Provides that, to be considered within the limits of the AOC, the elevation of the reclaimed area of surface mines may not vary from the premining elevation at any point by more than ± 20%. (§ 816.102)
- Establishes requirements to regrade/reclaim mined land and other disturbed areas using landforming techniques to replicate natural features and the premining topography to the extent consistent with stability requirements and the postmining land use. (§§ 780.12, 784.12, 816.102, and 817.102)
- Requires preparation of a digital terrain model of premining landforms as part of the permit application. Also requires preparation of an updated model of backfilled and regraded areas and excess spoil fills and refuse piles annually and upon application for bond release, with exceptions for inactive operations, lands eligible for remining, and operations smaller than 40 acres. (§§ 779.16, 783.16, 816.102, and 817.102)
- Allows the postmining elevation to exceed the original elevation when necessary to achieve maximum placement of spoil in the mined-out area or to create a more natural appearance for fills. (§§ 780.12, 780.35, 784.12, 784.35, 816.102, 816.105, and 817.102)
- Requires that operations be designed to minimize the volume of excess spoil placed in fills and the length of stream segments buried by fills. Also requires use of construction techniques that will minimize leaching of parameters of concern. (§§ 780.35, 784.35, 816.71, 816.102, 817.71, and 817.102)
- Requires that fills be constructed in controlled, compacted lifts of not more than 4 feet. Durable rock fills and fills with rock core chimney drains are no longer allowed. (§§ 816.71 through 816.73 and 817.71 through 817.73)
- Strengthens standards for rock underdrains in fills to improve long-term stability and function. (§§ 816.71 and 817.71)
- Prohibits construction of flat-topped fills unless necessary to achieve the approved postmining land use or to ensure stability. Requires use of landforming principles to create a natural-looking topography on completed fills. (§§ 816.71 and 817.71)
- Requires construction of ephemeral streams on top of fills, where possible and consistent with stability and water quality considerations, by use of natural stream-channel design and construction techniques. (§§ 816.71 and 817.71)
- Requires daily logs of fill construction operations. (§§ 816.71 and 817.71)

2.1.1.9 Exceptions to Approximate Original Contour Restoration Requirements.

- Requires that the applicant demonstrate, and the regulatory authority find, that, when compared with an operation on the same site designed in accordance with AOC restoration requirements, a proposed mountaintop

removal mining operation would not increase damage from flooding or result in increases in the amount or concentration of parameters of concern in discharges to groundwater or surface water. (§ 785.14)

- Requires that the applicant demonstrate, and the regulatory authority find, that a proposed mountaintop removal mining operation would not adversely affect any existing or approved use of surface water or groundwater or any designated use of surface water under the CWA. (§ 785.14)
- Provides that mountaintop removal mining operations must not damage natural watercourses, either within or outside the permit area. (§§ 785.14 and 824.11)
- Requires that the applicant demonstrate, and the regulatory authority find, that approval of a steep-slope AOC restoration variance would result in lesser adverse impacts to perennial and intermittent streams within the proposed permit area and to the aquatic ecology of the cumulative impact area than if the site were restored to the AOC. (§ 785.16)
- Prohibits approval of a steep-slope AOC restoration variance if doing so would result in construction of an excess spoil fill in a perennial or intermittent stream. (§ 785.16)
- Requires that the permittee post bond in an amount adequate to cover the cost of restoring the site to the AOC if the approved postmining land use is not implemented within the revegetation responsibility period. (§ 785.16)

2.1.1.10 Revegetation and Soil Management.

- Incorporates selected principles of the Forestry Reclamation Approach, including minimization of compaction of the root zone. (§§ 779.19, 779.21, 780.12, 783.19, 783.21, 784.12, 816.22, 816.111, 816.116, 817.22, 816.111, and 817.116)
- Requires that all reclaimed lands be revegetated with native species, regardless of the postmining land use, unless native species are inconsistent with that use and the use is actually implemented before the end of the revegetation responsibility period. (§§ 780.12, 784.12, 816.111, 816.116, 817.111, and 817.116)
- Requires that revegetation success standards be based upon the requirement to restore the land to a condition in which it is capable of supporting a variety of uses, not merely a single postmining land use. (§§ 816.116 and 817.116)
- Requires reforestation of land that was previously forested or that would revert to forest under natural succession. This requirement includes excess spoil fills. (§§ 780.12, 780.28, 784.12, 784.28, 816.111, 816.116, 817.111, and 817.116)
- Requires salvage and redistribution of organic materials, including vegetative debris, to control erosion, promote growth of vegetation, serve as a source of

native plant seeds and organisms, and increase the moisture retention capability of the soil. (§§ 780.12, 784.12, 816.22, and 817.22)

- Establishes stricter standards for use of soil substitutes and for demonstration of proper redistribution of soil materials. (§§ 780.12, 784.12, 816.22, and 817.22)
- Expands requirements for salvage of topsoil to include subsoil, based on root zone requirements of the revegetation to be established on the reclaimed area. (§§ 780.12, 784.12, 816.22, and 817.22)

2.1.1.11 Fish and Wildlife Protection and Enhancement.

- Establishes new mandatory fish and wildlife protection and enhancement requirements. Those requirements include establishment of a 300-foot buffer zone for perennial and intermittent streams. If the buffer zone is disturbed, it must be replanted with native trees and shrubs or other native species. (§§ 780.16, 784.16, 816.97, and 817.97)
- Adds provisions requiring enhancement of fish and wildlife outside the mined-out area under certain conditions to offset adverse impacts within the mined-out area. (§§ 780.16 and 784.16)
- Adds provisions whereby the regulatory authority, in consultation with state and federal fish and wildlife and CWA agencies, may prohibit disturbance of areas within the proposed permit boundaries that have exceptionally high value for fish and wildlife. [§§ 779.20(e) and 783.20(e)]

2.1.1.12 Miscellaneous

- Adds a requirement for a detailed surface-water control plan to prevent flooding and other adverse offsite impacts. (§§ 780.29 and 784.29)
- Adds a requirement for an engineer to examine and certify the functionality of the surface-water control system after every significant precipitation event. (§§ 816.34 and 817.34)
- Requires that the SMCRA regulatory authority consult with the CWA permitting authorities to coordinate the SMCRA permitting process and baseline data collection and monitoring requirements with CWA permitting activities and requirements to the extent practicable and consistent with consistent with each agency's statutory authority and responsibilities. (§§ 773.5, 780.19, 780.23, 784.19, and 784.23)
- Requires that permit applications be submitted in an electronic format to facilitate sharing among agencies and promote public participation. (§ 777.15)
- Requires establishment of trust funds or annuities to provide financial assurance for treatment of postmining discharges in perpetuity. (§ 800.18)
- Provides that a change from one postmining land use that the site was capable of supporting before mining to another use that the site was capable of

supporting before mining is not subject to the requirements governing approval of alternative postmining land uses, which would be limited to approval of higher or better uses. (§§ 780.24 and 784.24)

- Requires that an applicant for an alternative (higher or better) postmining land use demonstrate, and the regulatory authority find, that the proposed use would not adversely affect any existing or approved use of surface water or groundwater or any designated use of surface water under the CWA and, when compared with the conditions that would exist otherwise, would not result in increased damage from flooding. (§§ 780.24 and 784.24)
- Requires that an applicant for an alternative (higher or better) postmining land use provide additional documentation that the proposed use will be achieved after mining and reclamation. (§§ 780.24 and 784.24)
- Places additional restrictions on retention of mining-related structures. Requires that the size and characteristics of the structure be consistent with and proportional to the needs of the postmining land use, that the bond amount include the cost of removing the structure and reclaiming the land upon which it is located, and that the permittee remove the structure if it is not in use by the end of the revegetation responsibility period. (§§ 780.24 and 784.24)
- Adds specificity to the provisions concerning identification of alternative water sources and replacement of damaged water supplies. (§§ 780.22(b), 784.22(b), 816.40, and 817.40)

Table 2-1 serves as a side-by side comparison of the existing regulatory conditions and the proposed Stream Protection Rule.

Table 2-1: Side-by-Side Comparison of Status Quo and Proposed Stream Protection Rule

PRINCIPAL ELEMENT	BASELINE (EXISTING)	PROPOSED RULE
Stream Definition	The current hydrologic-centric approach based on hydrologic conditions and watershed size	An approach based on hydrologic, biologic, and physical characteristics of streams with no drainage area criteria
Baseline Data and Analysis	The current collection of data on a limited suite of chemical and geologic data related to groundwater and surface water sources and limited biological characterization	Sampling over a 12 month period for a full suite of chemicals; continuous flow measurements; and documentation of sediment, meteorology, stream form and function, and aquatic organisms from intermittent and perennial streams
Material Damage Definition	None. Preamble specifies that each state should develop criteria for material damage to the hydrologic balance outside the permit area and that OSM considers compliance with water-quality standards and effluent limitations as the only fixed criterion. 48 FR 43973, col. 1, September 26, 1983.	Defining “material damage” as a measurable adverse impact on water quality or quantity or designated use in an intermittent or perennial stream

PRINCIPAL ELEMENT	BASELINE (EXISTING)	PROPOSED RULE
Activities In or Near Streams	A prohibition on mining activities within 100 feet of streams, unless a disturbance is unavoidable or involves placement of a fill in the stream	A prohibition on mining activities within 100 feet of intermittent and perennial stream, with an allowance for fills under certain circumstances
Mining Through Streams	A requirement that all stream diversions and restored stream channels must use natural channel design techniques to restore or approximate pre-mining stream channel characteristics	Allowance of mining through intermittent or perennial streams if stream form and function can be restored
Monitoring During Mining and Reclamation	Monitoring of surface and ground waters for a limited suite of parameters that does not include a biological component; quarterly basis, but can be waived by the regulatory authority	Similar to 2nd bullet above, except that monitoring would not have to continue until restoration of the stream community had been demonstrated
Corrective Action Thresholds	Current regulations do require specific Corrective Action Thresholds, but require only that the permittee take action to correct noncompliance with permit conditions, water quality laws or regulations	The regulatory authority would establish Corrective Action Thresholds based on monitoring data that indicate environmental degradation prior to reach material damage; data would be reviewed quarterly
Surface Configuration and Fills	Current regulations do not specifically address landforming principles, but rather require that disturbed areas be backfilled and restored to AOC, with certain exceptions. Excess spoil should be minimized, with the maximum amount returned to the mined-out area. Placement of excess spoil and coal mine waste in intermittent and perennial streams must be avoided if possible or a range of alternatives identified to minimize impacts to fish, wildlife, and related environmental values	Similar to the 3rd bullet above, except that it would not adopt the AOC 20% rule and postmining elevations could not exceed pre-mining elevations based on restoration of pre-mining topographic landforms. Instead, tolerances for AOC configuration would be defined to allow AOC to be met in certain circumstances where pre-mining elevations would be exceeded. Additionally, regulatory authorities would set fill optimization policies based on topography and other site specific issues
AOC Exceptions	Current regulations allow AOC exceptions for mountaintop removal operations, subject to several requirements including no damage to natural water courses. AOC exceptions are also allowed for steep-slope mining operations provided the watershed will be improved to pre-mining conditions or conditions that would have existed had the areas been restored to AOC	Same as 3rd bullet above, except that the regulatory would not have to make a specific determination that the postmining land use (PMLU are achievable and feasible. Inclusion in the permit and reclamation plan is sufficient. AOC - steep slope: 785.16 (a) 8, cannot place fill in perennial or intermittent streams unless sufficient bond is in place to return to AOC if PMLU is not achieved by revegetation time limit requirement
Revegetation and Topsoil Management	Current regulations require revegetation in accordance with pre-mining land use or an approved PMLU	Same as 3rd bullet above, except that reforestation is required with exceptions in 816.11(a).for areas that had been forested at PAP or would revert to forest

PRINCIPAL ELEMENT	BASELINE (EXISTING)	PROPOSED RULE
Fish and Wildlife Protection and Enhancement	Under current regulations, the mine operator must minimize disturbances and adverse impacts on fish, wildlife, and related environmental values, particularly habitats of unusually high value for fish and wildlife. The mining operator must avoid disturbances, restore, or replace wetlands, riparian vegetation along rivers, streams, ponds, and lakes, Enhancement of all required if practicable. Mining activities cannot jeopardize endangered or threatened species, or destroy or adversely modify designated critical habitat. Where fish and wildlife habitat is the PMLU, select plant material based on value to the expected fish and wildlife	Same as 2nd bullet above, except that enhancement requirements would relate to mining activities that impact intermittent and perennial streams, not ephemeral streams. Enhancement activities would still occur in the same watershed as available or on the permitted area or allowed outside the watershed if no enhancement activities exist within the watershed. If outside the affected watershed, then enhancement would occur within the closest adjacent watershed

2.2 RATIONALE BASED ON INTENDED ENVIRONMENTAL IMPROVEMENTS

The need for the SPR based on four broad elements:

Need to Examine Rules and Regulations

OSM is proposing revisions to its rules and regulations to address gaps and ambiguities that weaken the agency's ability to accomplish its mission of protecting society and the environment from the adverse effects of surface coal mining operations. It is necessary, therefore, that the agency examine several provisions of its rules and regulations to ensure they protect the Nation's streams from the adverse effects of surface coal mining operations.

Need to Provide Clarification or Definitions

Some current rules and regulations have been subject to uneven interpretation and implementation by the regulated community, as well as by the state regulatory agencies charged with issuing and enforcing permits within their jurisdictions. As a result, surface coal mining activities in one state may not provide the same degree of protection for environmental resources, in particular streams, as in others. Thus, there is a need to strengthen and clarify regulations related to permitting.

Need to Extend Protections/Rules Nationwide

SMCRA requires and the public expects that streams will be protected regardless of where they exist. Previous attention to this issue has focused on the central Appalachian region of the U.S., but OSM has determined that this focus is not fair, appropriate, or scientifically valid or consistent with the principles of SMCRA. Streams are ecologically significant regardless of the region where they are located. Therefore, there is a need to revise the regulations to minimize the adverse effects of surface coal mining operations on streams.

Need to Provide Consistency/Enforceability Based on Science

As the federal agency responsible for SMCRA, OSM must ensure that its rules and regulations contribute to an overall regulatory environment that is scientifically valid, consistent, implementable, and enforceable.

2.3 EXISTING REGULATORY BASELINE ASSESSMENT

Background

The SMCRA was enacted in 1977, in part, to "establish a nationwide program to protect society and the environment from the adverse effects of surface coal mining operations." SMCRA requires the Secretary, acting through OSM, to promulgate rules and regulations necessary to carry out the purposes of the law. OSM is also mindful of its mandate to "assure that the coal supply essential to the Nation's energy requirements, and to its economic and social well-being is provided and [to] strike a balance between protection of the environment and agricultural productivity and the Nation's need for coal as an essential source of energy."

Specific to stream protection, SMCRA section 515(b)(10(B)(i) requires, among other things, that surface coal mining operations be conducted so as to prevent, to the extent possible using the best technology currently available, additional contributions of suspended solids to streamflow or runoff outside the permit area. SMCRA section 515(b)(24) provides that to the extent possible using the best technology currently available, surface coal mining and reclamation operations must minimize disturbances and adverse impacts of the operation on fish, wildlife, and related environmental values, and achieve enhancement of such resources where practicable.

Stream Buffer Zone Rules

In implementing these provisions, OSM developed what became known as a stream buffer zone rule, which went through three iterations from 1977 to 1983. While historically, both OSM and the state regulatory authorities have applied the stream buffer zone rule as allowing the placement of excess spoil fills, refuse piles, slurry impoundments, and sedimentation ponds in intermittent and perennial streams, there is considerable controversy over the proper interpretation of the existing stream buffer zone rule as it applies to placement of fill material in or near perennial and intermittent streams. Some interpretations of the existing rule are at odds with the underlying provisions of SMCRA or near perennial and intermittent streams. Some interpretations of the existing rule are at odds with the underlying provisions of SMCRA. Some interpretations of the existing rule are at odds with the underlying provisions of SMCRA.

The interpretation of the 1983 stream buffer zone rule was challenged in the late 1990s and the early 2000s, following OSM's first written interpretation of the rule in a document entitled "Summary Report-West Virginia Permit Review-Vandalia Resources, Inc. Permit No. S-2007-98." Through this document, OSM stated that the stream buffer zone does not apply to the footprint of a fill placed in a perennial or intermittent stream as part of a surface coal mining operation.

In July 1998, plaintiffs filed a lawsuit challenging this interpretation, and contending that SMCRA and the CWA were being improperly applied by the state regulatory authority, the West Virginia Department of Environmental Protection (WVDEP), and the Army Corps of Engineers

(COE) respectively. Bragg v. Robertson, 72 F.Supp.2d 642 (S.D. W.V. 1999). With respect to the stream buffer zone rule, the plaintiffs in Bragg v. Robertson, argued that the rule allowed mining activities through or within the buffer zone for a perennial or intermittent stream only if the activities were minor incursions and that the rule forbade substantial segments of the stream to be buried underneath excess spoil fills or other mining-related structures.

The parties settled the CWA issues in December 1998, and in 1999, WVDEP entered into a consent decree following discussions with the plaintiffs regarding its implementation of the SMCRA program. On the remaining stream buffer zone issue, the U.S. District Court for the Southern District of West Virginia ruled in favor of the plaintiffs on October 20, 1999, holding that the stream buffer zone applied to all segments of a stream as a whole. On appeal, the U.S. Court of Appeals for the Fourth Circuit reversed the district court's opinion, citing lack of jurisdiction under the Eleventh Amendment to the U.S. Constitution and failed to reach the merits of the holding applicable to the stream buffer zone issue. Bragg v. West Virginia Coal Association, 248 F.3d 275, 296 (4th Cir. 2001), cert. denied, 534 U.S. 1113 (2002).

In 2002, in Kentuckians for the Commonwealth, Inc. v. Rivenburgh, plaintiffs sued the COE alleging that the COE authorized the disposal of overburden waste from surface coal mining operations into streams in violation of Section 404 of the CWA. 204 F.Supp.2d 927 (S.D.W.V. 2002). Again, the U.S. District Court for the Southern District of West Virginia found in favor of the plaintiffs, stating, "SMCRA contains no provision authorizing disposal of overburden waste in streams, a conclusion further supported by the buffer zone rule." Id. at 942. In addition, the court held that the approval of waste disposal as fill material was beyond the authority of either the COE or the USEPA and issued an injunction prohibiting the COE from issuing CWA section 404 permits in the COE's Huntington district where the fill had no "constructive purpose." Id. at 942-43.

The government appealed this decision to the U.S. Court of Appeals for the Fourth Circuit, which rejected the district court's interpretation, stating, "SMCRA does not prohibit the discharge of surface coal mining excess spoil in waters of the United States." Kentuckians for the Commonwealth, Inc. v. Rivenburgh, 317 F.3d 425, 422 (4th Cir. 2003). The court further found that regulating valley fills was consistent with both the regulation and the statute, rejected the district court's conclusion that the statute only authorized issuance of permits under CWA Section 404 for "beneficial" fills, and held that neither the statute nor the 1977 regulation prohibited the COE from authorizing valley fills for waste disposal purposes under CWA Section 404, while rejecting the injunction issued by the district court as overly broad.

Mountaintop Removal and Valley Fill EIS and Bragg Settlement

As a result of the settlement on the CWA issues in the Bragg decision, the agencies agreed to prepare an EIS on a proposal to consider developing agency policies, guidance, and coordinated agency decision-making processes to minimize the environmental effects of mountaintop removal and valley fills. As part of the EIS process, the agencies conducted or funded over 30 studies documenting the impacts of mountaintop removal mining and excess spoil disposal in valley fills.

As part of a fill inventory conducted for the EIS, the agencies found that while the average number of fills per year had actually decreased in the period from 1995 to 1998 compared to

1985 to 1989 and 1990 to 1994, the average size of the fills had increased by 72 percent with the average length of stream impacts increasing by over 224 percent. Another study found that almost 1200 miles of headwater streams were directly impacted by surface coal mining operation from 1992 to 2002, and that 724 miles of stream were covered by valley fills in the period from 1985 to 2001.

The Final Programmatic EIS coming out of the Bragg litigation was completed in 2005 and is available at http://www.epa.gov/region3/mtntop/eis2005.htm.

Other Agency Initiatives

Even before the stream buffer zone rule litigation, in 1997, the U.S. Fish and Wildlife Service (USFWS) undertook an informal inventory of stream impacts resulting from valley fills and sediment ponds in West Virginia, Kentucky, and Virginia. The next year, the USEPA, COE, OSM, and USFWS, after meeting to discuss mountaintop removal and valley fills at an USEPA Region 3 forum called "Federal Regulatory Operations Group," issued a statement of mutual intent agreeing to study impacts from and regulatory controls on mountaintop removal and valley fills.

As part of routine oversight activities and separate from the mountaintop removal/valley fill EIS, OSM conducted studies in Kentucky, Virginia, and West Virginia to determine how the regulatory authorities were administering the SMCRA programs regarding AOC and postmining land use requirements. When permit files and reclaimed mines were examined, OSM found it difficult to distinguish between the reclamation configuration of mines that were not reclaimed to AOC and the reclamation configuration of mines that were reclaimed to AOC.

There were no clear differences in the number and size of the excess spoil fills, and non-AOC mines should typically have larger or more numerous fills. OSM determined that typically, coal mine operators could have retained more spoil on mined-out areas under applicable AOC requirements than they were actually retaining.

OSM also found that in many instances coal mine operators were overestimating the anticipated volume of excess spoil. As a result, OSM concluded that coal companies were designing fills larger than necessary to accommodate the anticipated excess spoil. Where fills are larger than needed, more land outside the coal extraction area is disturbed. OSM attributed these problems, in part, to lack of or inadequate regulatory guidance. As a result, OSM recommended that each regulatory authority work with the agency to develop enhanced guidance on material balance determinations, spoil management, and AOC, which Kentucky, West Virginia, and Virginia did. 69 CFR 1036, 1038 (January 7, 2004).

2004 and 2008 Stream Buffer Zone Rules

Although Kentucky, Virginia, and West Virginia developed enhanced guidance to optimize fill placement, OSM determined that although most excess spoil is attributable to steep slope mining in Appalachia, excess spoil was also generated from surface mining activities throughout the country and thus a revision to the national regulatory program was necessary.

In its notice to initiate a rulemaking regarding excess spoil, stream buffer zones, and diversions, OSM noted that existing regulations focused on the stability of excess spoil material and erosion

control, but did not adequately address SMCRA's requirement under section 515(b)(22)(I) to place all spoil material so that all other provisions of SMCRA are met, which would include hydrologic balance, water quality, revegetation, and other performance standards. 69 FR 1036, 1038 (January 7, 2004). Therefore, OSM sought to undertake this rulemaking to ensure the minimization of the volume of excess spoil and the effects to the hydrologic balance, fish, wildlife, and other environmental resources.

Taking these considerations into account, OSM published a proposed "excess spoil/stream buffer zone" rule in the Federal Register on January 7, 2004. 69 FR 1036. In the same notice, OSM also announced the availability of the draft environmental impact assessment for the proposed rule, which concluded preliminarily that the changes it was proposing would have no significant impacts on the human environment and that a finding of no significant impact would likely be prepared upon finalizing the environmental assessment.

After receiving many comments on the draft environmental assessment and further consideration, OSM concluded that further analysis of the effects on the human environment was warranted. On June 16, 2005, OSM announced in the Federal Register (70 FR 35112) that the agency would prepare an EIS to analyze the effects of the rulemaking initiative, and asked for the public's suggestions on the issues and alternatives to be examined.

Litigation

Following a public comment and several public meetings, OSM announced the availability of the proposed excess spoil minimization-stream buffer zone rule and its associated draft EIS on August 24, 2007. On December 12, 2008, OSM published a final rule modifying the circumstances under which mining activities may be conducted in or near perennial or intermittent streams. The rule took effect on January 12, 2009 and was challenged by a total of nine organizations in two separate complaints filed on December 22, 2008 and January 12, 2009: Coal River Mountain Watch, et al. v. Salazar and National Parks Conservation Ass'n v. Salazar. A settlement agreement was signed by the parties on March 19, 2010, by which OSM agreed to use best efforts to sign a proposed rule by February 28, 2011 and a final rule by June 29, 2012, and to consult with FWS pursuant to the Endangered Species Act, as appropriate prior to signing the final action. On April 2, 2010, the court granted the parties' motion to hold the judicial proceedings in abeyance.

Memorandum of Understanding – June 2009

On June 11, 2009, OSM, EPA, and the U.S. Army (representing the Corps of Engineers) entered into a Memorandum of Understanding (MOU). One purpose of the MOU was to establish an Interagency Action Plan (IAP) to reduce the harmful environmental consequences of surface coal mining operations in the Appalachian region, while ensuring future mining remains consistent with federal law. The IAP's elements include short-term actions to minimize the adverse environmental effects of Appalachian surface coal mining; a commitment to undertake longer-term regulatory actions related to Appalachian surface coal mining; coordinated reviews of permit applications under the CWA and SMCRA; and a commitment to engage in robust public participation.

Pursuant to the MOU, in the short term, OSM agreed to issue guidance clarifying application of the 1983 Stream Buffer Zone Rule, if the 2008 Stream Buffer Zone (SBZ) was vacated by the U.S. district court as requested by the Secretary of the Interior. OSM also agreed to reevaluate its oversight of state regulatory programs and to remove impediments to its ability to require correction of permit defects. In the long term, OSM agreed to consider revisions to key provisions of SMCRA, including the Stream Buffer Zone rule and AOC requirements.

Nationwide Permit 21

As part of the MOU, the COE agreed to issue a public notice to seek comment on the proposed action to modify Nationwide Permit 21 (NWP 21) to preclude its use in the Appalachian region, which it published in the Federal Register on July 15, 2009. NWP 21 authorizes the discharge of dredged or fill material from surface coal mining operations into waters of the United States and is issued under section 404(e) of the CWA.

Section 404(e) authorizes the COE to issue general permits on a nationwide basis for categories of activities involving the discharge of dredged or fill material, such as surface coal mining, where the activities are similar in nature and cause only minimal adverse effect when performed separately and minimal cumulative effects on the environment. First issued in 1982, the current version of NWP 21 was issued on March 12, 2007, and authorizes "discharges of dredged or fill material into waters of the United States associated with surface coal mining and reclamation operations provided the activities are already authorized, or are currently being processed as part of an integrated permit processing procedure, by the Department of Interior (DOI), Office of Surface Mining (OSM), or by states with approved programs under Title V of the Surface Mining Control and Reclamation Act of 1977."

In lieu of issuing a general permit such as NWP 21, the COE is also authorized to issue individual permits under section 404(a) of the CWA for discharges of dredged or fill material that occur at "specified disposal sites." Public notice and an opportunity for public hearings must be afforded prior to issuance of an individual permit under section 404(a), and the permit must comply with section 404(b)(1) guidelines.

After notice and over 23,000 public comments on the COE's July 15, 2009, Federal Register notice, the COE issued notice on June 18, 2010 that effective immediately, it was suspending use of NWP 21 in six Appalachian states: Kentucky, Virginia, West Virginia, Pennsylvania, Ohio, and Tennessee. The COE reasoned that:

"Using the individual permit process for those activities will provide more information for the Corps to consider in making decisions on these permit applications because of increased public involvement, such as the opportunity to comment on public notices for individual surface coal mining activities in Appalachia. This additional information could help improve not only the Corps analysis of potential individual and cumulative adverse effects of the proposed activity on the aquatic environment, but also on the potential adverse effects on other public interest review factors listed at 33 Code of Federal Regulations (CFR) 320.4(a)(1), such as conservation, aesthetics, economics, land use, recreation, fish and wildlife values, energy needs, and general considerations of property ownership, to the extent that those public interest factors are relevant to waters of the United States subject to CWA jurisdiction and within the Corps Federal control and responsibility." 75 FR 34711, 34713 (June 18, 2010)

As a result, surface mining operations in these states are required to obtain individual permits from the COE in order to discharge dredged or fill material from surface coal mining operations into waters of the United States. NWP 21 activities already approved prior to this notice continue to be authorized until the current NWP 21 expires on March 18, 2012, but these authorizations cannot be modified to allow additional discharges. NWP 21 is still in effect in the remainder of the country.

Advance Notice of Proposed Rulemaking

On November 30, 2009, OSM published an Advance Notice of Proposed Rulemaking (ANPR) nine soliciting comments on ten potential rulemaking alternatives. The agency also invited the public to identify other rules that the OSM should consider revising, and it announced its intent to prepare an EIS to supplement the EIS that was prepared for the 2008 SBZ rule. OSM received approximately 32,750 comments during the 30-day comment period. After evaluating the comments, the agency determined that development of a comprehensive stream protection rule would be the most appropriate and effective method of achieving the goals set forth in SMCRA, as well as the MOU and ANPR. It also concluded that the new rule should not be limited to the Appalachian surface coal mining region, but be applicable nationwide. The broader scope of the new stream protection rule required that the agency prepare a new EIS rather than supplement the one prepared for the 2008 SBZ rule.

Notices of Intent – Stream Protection Rule

On April 30, 2010, OSM published notice of its intent to prepare an EIS to analyze the effects of potential revisions to its rules and regulations under SMCRA to improve the protection of streams from the adverse impacts of surface coal mining operations. The agency set forth eleven principal elements under consideration as part of its revisions to various SMCRA rules and regulations. Those principal elements are discussed in a subsequent section of this chapter. OSM received 25 comments during the 30-day comment period ending June 1, 2010.

On June 18, 2010, OSM re-opened the scoping period in order to offer the public additional opportunities to provide comment on the scope of the EIS and revisions to the SMCRA rules and regulations. In addition to extending the scoping period by 45 days to July 30, 2010, the agency also announced its intent to host nine public scoping open houses in coal producing regions across the U.S. The Notice of Intent also expanded on the eleven principal elements by including possible alternatives for each element. The results of these scoping efforts are summarized in a subsequent section of this chapter.

2.4 ALTERNATIVE REGULATORY APPROACHES

The consideration of various regulatory approaches is an aspect of the SPR RIA. Each of these alternatives is defined below.

When a statute establishes a specific regulatory requirement and the agency is considering a more stringent standard, it is important to examine the benefits and costs of reasonable alternatives that reflect the range of the agency's statutory discretion, including the specific statutory requirement.

The RIA examines three alternatives, which have been requested by the Office of Management and Budget (OMB) because of the expected significance of the SPR's economic impact. The baseline or no action alternative, the most stringent version of the rule, and the proposed or preferred version of the rule are assessed in the RIA. The Alternatives are

1. The current state of the SMCRA regulations pertaining to each of the 11 principal elements. This represents the baseline for comparison with other alternatives.
2. Provisions or approaches that are considered the most protective of natural resources among the alternatives. These provisions impose a substantially increased administrative and economic burden on the mining industry.
3. OSM's Proposed SPR. The Proposed SPR attempts to balance the protection of natural resources with imposing a reasonable administrative and economic burden on the coal mining industry.

2.5 ECONOMIC JUSTIFICATION FOR THE RULE

Market Failure

Market failure is defined as the inability of markets to reflect the full social costs or benefits of a good, service, or state of the world. Therefore, when markets fail, the result will be inefficient or unfavorable allocation of resources. Since economic theory wants to achieve efficiency, environmental economics is used as a tool to find a balance in the world's system of resource use.

The key to the environmental economics approach is that there is value from the environment and value from the economic activity. The goal is to balance the economic activity with environmental degradation by taking all costs and benefits into account. This balancing is central to OSM's mission in regulating coal mining activities across the country, and this proposed rule must ensure that economy and environment are balanced in the context of future coal mining activities.

Economic Justification within Environmental Economics

As part of the economic justification of the SPR, it is important to examine the externalities (economic costs and benefits of coal mining that adversely affect the environment and are not reflected in prices) under its current regulatory environment. Hard data on the overall economic costs and benefits of current regulatory environment related to coal mining is not easy obtain. Several available studies and reports discussing the economic costs and benefits of coal mining are reviewed below.

Indications of the Economic Costs of Coal in the Current Regulatory Environment

In economics, an external cost, or externality, is a negative effect of an economic activity on a third party. When coal is mined and used to generate electric power, external costs include the impacts of water pollution, toxic coal waste, air pollution, and the long-term damage to ecosystems and human health.

According to the National Academies of Sciences, burning coal to generate electricity in the U.S. causes about $62 billion a year in "hidden costs" for environmental damage, not including expenses related to global warming. This cost was part of $120 billion the group identified as total damages from the use of energy in 2005, according to a 2009 report by the Academy's National Research Council.[4]

External costs of coal mining and power generation include the following:[5]

- Reduction in life expectancy (particulates, sulfur dioxide, ozone, heavy metals, benzene, radionuclides, etc.)
- Respiratory hospital admissions (particulates, ozone, sulfur dioxide)
- Congestive heart failure (particulates and carbon monoxide)
- Non-fatal cancer, osteoporosis, ataxia, renal dysfunction (benzene, radionuclides, heavy metal, etc.)
- Chronic bronchitis, asthma attacks, etc. (particulates, ozone)
- Loss of IQ (mercury)
- Degradation and soiling of buildings (sulfur dioxide, acid deposition, particulates)
- Reduction of crop yields (NOx, sulfur dioxide, ozone, acid deposition); some emissions may also have a fertilizing effect (nitrogen and sulfur deposition)
- Global warming (carbon dioxide, methane, nitrous oxide)
- Ecosystem loss and degradation

A 2010 report from the Clean Air Task Force, *The Toll From Coal* found that, in the United States, particle pollution from existing coal power plants is expected to cause some 13,200 premature deaths in 2010, as well as 9,700 additional hospitalizations and 20,000 heart attacks.[6]

Estimated mortality figures for 2010 have Pennsylvania leading the nation with 1,359 premature deaths, 1,016 people admitted to the hospital, and 2,298 additional heart attacks. Ohio comes in second with 1,221 additional premature deaths; New York takes third with 945 dead from coal pollution. Per capita, the figures change slightly: West Virginia is first in the nation, with an estimated 14.7 coal-related deaths per 100,000 adults. Pennsylvania and Ohio tie for second, with 13.9; Kentucky comes in third at 12.6.

The report found that the total monetized value of these adverse health impacts amounts to more than $100 billion per year. This burden is not distributed evenly across the population. Adverse impacts are especially severe for the elderly, children, and those with respiratory disease. In addition, the poor, minority groups, and people who live in areas downwind of multiple power

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[4] National Research Council, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use,* Washington, DC, 2009.

[5] Source: http://www.sourcewatch.org/index.php?title=External_costs_of_coal#Types_of_external_costs, accessed on January 3, 2011.

[6] Source: http://www.catf.us/resources/publications/view/138, accessed on January 3, 2011.

plants are likely to be disproportionately exposed to the health risks and costs of fine particle pollution.

Every year China is spends $250 billion in hidden costs due to its reliance on coal, according to a report compiled over three years by top Chinese economists. These hidden costs are in the form of both environmental degradation and social ills. *The True Cost of Coal in China*, commissioned by Greenpeace China, World Wildlife Foundation, and the Energy Foundation, examines the economic costs of China's continued reliance on coal as a major energy source.[7]

An analysis of U.S. coal prices in the February 3, 2010 issue of *The Economist* concluded that "coal dependence in the U.S. has continued largely because coal has remained so cheap, and coal has remained cheap because society has not forced mining operations and power companies to internalize the costs of the environmental, economic, and health damage associated with coal into the price. Coal continues to dominate simply because the market doesn't reflect social costs. That's not a problem with renewables. That's a problem of economics and of governance."[8]

A 2009 doctoral dissertation by Shruti Khadka Mishra at The Ohio State University examines the externalities of coal-based electricity generation and evaluates the externalities inadequately addressed by Ohio's current regulatory framework. Three major areas addressed by the research are evaluation of coalmining impacts on lake recreation; estimation of reclamation costs and revisiting the taxes on coal mined in Ohio; and the impacts of internalizing the externalities on electricity portfolio of Ohio.

The main conclusion of Mishra's dissertation is that Ohio's advanced electricity portfolio includes clean coal and renewable sources leaving leeway for continued large dependency on coal. The argument for deployment of coal-fired electricity to a large extent is the lower upfront private cost of electricity. However, ongoing coal-mining impacts in Ohio and unregulated Carbon dioxide (CO_2) suggest that the current price structure of Ohio does not reflect the true cost of electricity. This inability of the prevailing cost structure to fully internalize the externalities misleads the decision makers from providing a level playing field for renewable energy sectors which could reduce water pollution, global warming, and potentially create green jobs.[9]

Indications of the Economic Benefits of Coal Mining in the Current Regulatory Environment

According to a 2010 economic impact study by the National Mining Association (NMA) of the U.S. mining industry (all types of mining) in 2008, the coal segment of U.S. mining accounted for 555,270 jobs, $36.3 billion in labor income and $65.7 billion in contribution to Gross Domestic Product (GDP). Average wages and salaries in coal mine operations (excluding support activities and transportation) were approximately $72,200 in 2008.[10]

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[7] Greenpeace China, World Wildlife Foundation, and the Energy Foundation, *The True Cost of Coal in China*, 2008.

[8] The Economist, *On the price of coal*, February 3, 2010, http://www.economist.com/blogs/freeexchange/2010/02/energy_transitionaccessed on January 2, 2011.

[9] Khadka Mishra, Shruti, *Estimation of Externality Costs of Electricity Generation From Coal: An OH-MARKAL Extension*, Doctoral Dissertation, Ohio State University, 2009, accessed online on December 28, 2010 at: http://etd.ohiolink.edu/view.cgi?acc_num=osu1259703337

[10] National Mining Association, *The Economic Contributions of U.S. Mining in 2008*

Overall, coal mining, including transportation of coal products and mining support activities allocated to coal mining, were responsible for approximately 31 percent of U.S. mining's total employment contribution, 34 percent of total labor income and 35 percent of total contribution to GDP.

Some states have conducted studies of the economic benefits of the coal mining industry.

A 2004 Kentucky study found that the Kentucky coal industry:[11]

- Employed 15,012 miners earning over $759 million in wages during 2004.
- Created 61,158 jobs statewide.
- Paid over $183.94 million in severance taxes during fiscal year (FY) 2004-05 and generated total state tax revenues of about $528.3 million.
- Was a $4.13 billion industry that brought into Kentucky receipts totaling about $3.25 billion from 23 states and 4 countries in FY 2004-05.
- Created economic activity throughout Kentucky totaling $8.97 billion.

According to a 2009 study of coal's economic impact in Utah in 2007, 24 million tons of coal-2 percent of all national production-were mined in Utah in 2007 (the most recent year for which detailed statistics are available). The coal mining industry accounted for approximately 4,700 jobs; 1,900 directly, with another 2,800 through indirect "ripple effects." Approximately 85 percent of the jobs were in the three coal-producing counties. The industry's direct financial impact to the state was $196 million for the year, two-thirds of this total going to Carbon, Emery, and Sevier Counties. [12]

According to the North Dakota State University Agricultural Economics Department, the state's lignite industry is the fifth largest industry, following agriculture, tourism, manufacturing, and petroleum. In 2008, more than 28,000 jobs in North Dakota result either directly or indirectly from the coal mining and power generating industries. In fact, people working for the coal industry in North Dakota enjoy some of the state's highest wages. North Dakota's economy receives about $3 billion in total business activity due to coal per year, and nearly $100 million in state tax revenue annually.[13]

A 2010 economic study of coal in West Virginia found that coal mining had the following overall economic impacts in 2008:[14]

A report prepared by PricewaterhouseCoopers, October 2010

[11] Study updated from the University of Kentucky Center for Business and Economic Research. *Economic Impact Analysis of Coal in Kentucky, (1995*) to 2004 by Haywood and Baldwin.

[12] Pamela S. Perlich, Michael T. Hogue and John C. Downen, *The Structure and Economic Impact of Utah's Coal Industry,"* Utah Bureau of Economic and Business Research at the Eccles School of Business. Accessed online on December 29, 2010 at: http://www.unews.utah.edu/p/?r=070710-1

[13] North Dakota State University, Economics Development, Economic Impact of Lignite Coal in North Dakota, 2010. Accessed online on February 15, 2011: https://www.lignite.com/?id=100

[14] *The West Virginia Coal Economy in 2008*, by Marshall University and West Virginia University, 2010. (Partially funded by the West Virginia Coal Association)

- Total number of jobs created was over 63,000.
- Total business volume generated was $25.53billion.
- Total employee compensation was nearly $3.6 billion.
- Total value added was $7.6 billion

According to a 2010 University of Wyoming economic study, the Powder River Basin (PRB) in Wyoming contains the largest reserve of low cost hydrocarbons on the planet. This report finds that PRB coal should be considered a strategic asset for the U.S. economy that: [15]

- Helps keep electricity rates low in the Midwest & South,
- Ensures low cost, reliable electricity,
- Maintains a competitive restraint on natural gas prices,
- Acts as a low-cost cushion to absorb high cost sources for electric power, and
- Serves as a critical backstop for future production of electricity and liquid fuels.

Environmental Economics: Some Concepts on Coal's Current Economic Costs and Benefits

The identification of an economic justification for the OSM SPR requires us to go beyond these partial indications of the economic costs and benefits of coal mining in its current regulatory environment, and reach into the field of environmental economics, which is a distinct branch of economics that acknowledges the value of both the environment and economic activity and makes choices based on those values. *These concepts help us understand how the current market (private industry including the coal mining industry) fails to address of costs of protecting the environment in the way in which the SPR proposes to do.*

The goal of environmental economics is to balance an economic activity (coal mining) and its environmental impacts (stream protection) by taking into account all the costs and benefits. Associated theories are designed to take into account pollution and natural resource depletion, which the current model of market systems fails to do. Environmental economists argue that this "failure" needs to be addressed by correcting prices so they take into account "external" costs.

By definition, external costs are uncompensated side effects of human actions. For example, if a stream is polluted by runoff from a coal mine, the people downstream suffer a negative external cost or externality.

The assumption in environmental economics is that the environment provides resources (renewable and non-renewable), assimilates waste, and provides aesthetic pleasure to humans. These are economic functions because they have positive economic value and could be bought and sold in the market place. However, traditionally, their value was not recognized because there is no market for these services (to establish a price), which is why economists talk about "market failure".

[15] Considine, Timothy, *Powder River Basin Coal: Powering America* (Final Report to The Wyoming Mining Association), December 21, 2009

3 Methodology

3.1 DEFINITION OF ECONOMIC COSTS, BENEFITS, TRANSFERS, AND IMPACTS

3.1.1 Economic Benefits

Overall Definition

In our everyday lives, we put values to many items. Many items carry a price tag that makes an interaction between a seller and purchaser simple and straightforward; however, that is not the case for the goods and services that we do not often see a price tag on, such as clean air and water, unfragmented wildlife habitat, and scenic views. These intrinsic activities associated with our environments have been referred to variously throughout the literature as ecosystem functions, services, processes, assets, and benefits. Costanza et al. (1997) defines ecosystem functions as *the habitat, biological, or system properties or processes of ecosystems*; while ecosystem goods (i.e., food) and services (i.e., waste assimilation) are the *benefits we derive from the ecosystem functions*. Chee (2004) citing Daily (1997) defines ecosystem services as *the conditions and processes through which natural ecosystems and the species that comprise them, sustain and fulfill human life*. This concept incorporates *the delivery, provision, production, protection, or maintenance for a set of goods and services that people perceive as important*. Alternatively, Boyd (2007) defines ecosystem components as *resources (i.e., surface water, oceans, vegetation, and species) and ecosystem processes and functions as the biological, chemical, and physical interactions of ecosystems that are described through science*. Boyd (2007) defines ecosystem services as the *aspects of nature that society uses, consumes, or enjoys to experience those benefits* (i.e., recreations, aesthetics, harvests, etc.). They are the end products of the environment that directly yield human well-being. Further, Boyd (2007) indentifies that ecosystem services are end products, aspects of the environment that we make choices about. Iovanna & Griffiths (2006) in describing the USEPA methods for defining ecological benefits and benefits transfers described ecological benefits as those things (e.g., that which is valued) which are conferred through ecosystem service flows. Accordingly, ecosystem services are *those ecosystem processes that contribute to human well-being* (Iovanna & Griffiths 2006). They further identify how the USEPA categorizes ecological benefits (1) the production of marketed goods, (2) recreation and aesthetics, (3) protection of health and property, and (4) non- or passive use values (Iovanna & Griffiths 2006).

To value those services and functions, classical economic theories of preferences and pricing have developed mechanisms to determine the price or value of a good that for all intents and purposes does not have a monetary value, but does have intrinsic value to all consumers. Damigos (2005) defines the basic concept associated with Total Economic Value (TEV) as being comprised of use values and non-use (passive) values. Use values are (1) the values we receive directly from a resource (direct use) such as wood for paper or pulp, or game species such as deer or fish; (2) indirect use from ecosystem services such as clean water and air; and (3) the option value of a resource knowing that it exists for personal future use. Non-use values include existence values, which indicate the personal value of knowing something is there even though it may never be personally used and bequest value, which is the value to ensure that a resource is available for future generations (Damigos 2005, Edwards & Abivardi 1997).

Chee (2004) indicates three principal techniques for developing monetary valuation for items; (1) market-based approaches, (2) surrogate market approaches, and (3) simulated market approaches. Table 3-1 lists the type of techniques applicable to different markets. Table 3-2 provides a brief definition to various techniques and the benefits and drawbacks of each of those techniques. For valuing environmental services, stated preference techniques have become one of the standard tools used to make a determination of monetization of non-market goods. Contingent valuation (CV), attributed to Ciracy-Wantrup, provides a mechanism for respondents to provide personal valuations (e.g., willingness-to-pay [WTP] or willingness-to-accept [WTA]) of specific attributes derived from questionnaires or interviews (Chee 2004). Benefit transfer (BT) analyses provide an overview and compilation of studies with existing WTP or WTA values for specific ecosystem services or functions. Dumas, Schuhmann, & Whitehead (2005) indicate that BTs have been used since the 1950s to provide estimates associated with a study site to another policy site, but become an essential tool in the mid-1990s. BT has four subcategories, benefit estimate transfer (BET), benefit function transfer, meta-analysis, and preference calibration transfer (PCT) (Dumas & Whitehead 2005). Only the BET methodology does not create new economic calculations based on data from other studies.

Table 3-1: Valuing Ecological Services by Market Type and Techniques

Market	Basis of Approach	Main Techniques
Market-based	Production Approach	Production function analysis (PF), Replacement or Restoration cost (RC)
Surrogate market	Revealed Preference	Avoided cost (AC), Factor income, Travel cost (TC), Hedonic pricing (HP)
Simulated market	Stated Preference	CV, BT

Adapted from Chee 2004; Dumas, Schuhmann, & Whitehead 2005; Farber, Costanza, & Wilson, 2002

Table 3-2: Valuation Techniques Benefits and Drawbacks

Valuation Technique	Definition	Benefit	Drawbacks
PF	Estimating the contribution an ecosystem service makes to the production of some marketed/marketable service.	Relies on production or cost data, which can be more readily available	• Lack of adequate data. • Lack of understanding of the causal relationships between the marketed good and the ecosystem services. • Measure of value of the ecosystem services based on real market prices that do not fully capture ecosystem services value.
RC	Assesses the value of the ecosystem service by how much it costs to replace/restore it after it has been damaged with the objective to be to reinstate the lost consumer surplus and non-use value.	Relies on the actual cost to complete a defined activity	• Only provides the minimum value for the ecosystem service as there are many components that fully define the service • The optimum level of replacement should be determined by the amenity benefits back to society.

Valuation Technique	Definition	Benefit	Drawbacks
TC	Determines values of individual preference for non-market good where consumption is commensurate with the costs of travel to acquire it.	Predominantly used with outdoor recreation. Gathers data associated with a typical trip activity.	• Can have analyst bias on which values to include. • Difficult to determine the extent aggregate costs reflect the values of the service. • If visitors fail to recognize the importance of existence values, then that characteristic is absent from the valuation. • Hard to identify values are often overlooked and unpriced.
HP	The value an individual places on a service is based on the attributes it possesses; it is usually revealed in the market price.	Often used to value aspects associated with real estate. Implication that there exists a set of measurable attributes that will predict the price of a commodity when traded.	• Finding suitable variables to measure ecosystem attributes can be difficult. • Depends on sets of prior transactions that are typically absent from ecosystem service valuations. • Gives inaccurate estimates of environmental externalities if buyers lack reliable information about relevant environmental variables.
CV	This procedure is based on a hypothetical market in which people are asked to determine through questionnaires and/or interviews their demand function for a certain environmental good/service	It can provide a WTP or a WTA bid for environmental goods and services that do not have a market price	• Biases that can arise from the survey design and execution. • Zero bids are allowed, which can signal that the service has no value to person, that the person may be opposed to paying, a form of protest, or the belief that paying is the responsibility of some other entity. • Respondents may answer as citizens with a desire to do their fair share, rather than as an individual consumer, which could lead to double-counting. • Strategic behaviors can also be observed such as free-riding and over- and underbidding. • Surveys lack incentives for respondents to put much thought into their responses.
BT	Developed for situations where time and/or money costs of primary data collection for original studies are prohibitive. Environmental benefit estimates from existing case studies are spatially and temporally transferred to a new policy case study area.	More rapid and cost effective method than providing original research for a particular policy.	• Consumer surplus from the study site must be theoretically and methodologically valid. • The populations between the study site and the policy site should be similar. • Difference between pre-policy and post-policy quality/quantity levels should be similar across the study and policy sites. • The study and policy sites must be similar in terms of environmental characteristics. • Distribution of property rights and other institutions must be similar across the sites.

Adapted from Chee 2004; Dumas, Schuhmann, & Whitehead 2005; Brouwer 2000, Howley, Hynes, & O'Donoghue 2010, Kahneman & Knetsch 1992.

For this RIA a combination of two methods were determined most appropriate to develop ecological services values as affected by the proposed rule. The methods selected were the AC for replacement or restoration based on estimated potential restoration values and a BET of similar ecosystem services that would be affected from the proposed rule. Due to time

constraints associated with the priority of establishing the proposed rule, a comparison of past CV studies and meta-analyses has been undertaken. This charting of values provides a range of WTP amounts for various ecological services, which match with the ecological services being supported through the implementation of the proposed rule. Appendix 1 provides a summary of the various WTP values, benefit values, ACs, and predicted costs for various ecological services.

Riparian buffers provide numerous ecological services. They provide aquatic values from vegetation shading streams, resulting in more temperate waters; detritus for downstream foodwebs; and cover and habitat. They provide water quality benefits associated with vegetative root structures to hold native soils and to trap sediments, particulates, and nutrients suspended in stormwater flows across the landscape prior to entering a confined stream system. They provide wildlife and recreational aspects for food, cover, and corridors for movement, as well as opportunities for consumptive wildlife uses such as hunting and non-consumptive such as wildlife watching. Riparian buffers vary greatly from ecosystem to ecosystem. Some buffers in more temperate areas with higher rainfall can provide large hard-mast producing species, while in arid climates, riparian buffers consists of hardy, shrubby, thorny species that provide many of the same functions to different species. In addition to the direct benefits that these areas provide, they also provide intrinsic benefits associated with their existence and as first order ecosystems that provide the framework for larger more complex interaction at regional watershed levels.

3.1.2 Economic Costs

Overall Definition

The cost of the SPR is the full value of any resource in its best alternative use (opportunity cost). This may be estimated by the financial expenses incurred by a coal mine operator or state regulatory authority (SRA) in meeting the requirements placed upon them by the rule, or any expenses incurred by the federal and state governments in carrying out the implementation and enforcement of the rule. Costs also include any environmental, resource, human health, mortality, or other social impacts that are detrimental in nature. Costs include any capital (and the opportunity costs of this capital) and recurrent expenditure, administrative costs, monitoring and enforcement costs, and research and development costs. Economic costs include market and non-market costs, private and social ones. Mining costs include data collection, efforts to mine while avoiding streams, stream, stream buffer, and land restoration (including addition of topsoil and revegetation), and carrying costs for increased length of bond coverage and financial assurance coverage. Appendix 2 provides the various mining cost elements.

3.1.3 Economic Transfers

By definition, an economic transfer occurs when wealth or income is redistributed without any direct change in aggregate social welfare. Three potential transfers should be considered for evaluation in the final RIA:

1. **Coal Production Shifts**: Considerable attention has been given to regional shifts in coal production and mining method shifts. These could be seen as a form of “transfer” of rule-related benefits and costs. Available data on these shifts was discussed earlier in this report. A few important summary points should be considered in the context of transfers:

a. Regional Production Shifts: Analysis for both the EIS and RIA point to a potential loss of coal production from Eastern coal locations (principally the Appalachian Basin) to Western and Illinois Basin sources. It is important to note that these shifts have been underway for several years. It is likely that the SPR could add to these regional shifts. These future shifts could carry the economic benefits (production, sales, employment, payroll, and abandoned mine land (AML), severance taxes and royalties) associated with coal mining in Eastern states to Illinois Basin and Western states. One potential impact of these regional shifts could also be increases and decreases in the coal revenues and profits of coal mining companies. Those companies with Western mining operations would appear to stand to gain, and those with their primary operations in the East could be placed at a disadvantage.

b. Mining method shifts, especially those from surface mining to underground mining could have similar effects in benefitting coal companies in a position to capture the new underground mining business created by the shift from surface mining to underground mining.

2. **Costs Passed Along to Customers**: A second type of transfer could be represented by the actions by coal producers to pass along any increased cost of production related to the SPR to their customers, namely electric power companies and heavy metals (steel and other primary metals) manufacturing industries. Historically, coal producers have been able to pass along their increased costs to customers. Given the slowly recovering nature of the general economy, it may be more difficult for coal companies to pass along SPR costs to their customers.

3. **Intergovernmental and Private to Public Sector Cost Shifts**: A third potential type of transfer could relate to the transfer of any increased cost of production, mine site protection and reclamation, or other SPR-related cost from one level of government to another (for example, an unfunded mandate created by the rule that creates added regulatory or environmental cleanup costs to state and local governments.) A second type of transfer in this category could be a transfer of rule compliance costs from a private entity (coal mining company) to the public sector (federal, tribal, state, or local government).

INSERT INFORMATION FROM THE LEXINGTON WORK EFFORT TO IDENTIFY THE ECONOMIC BENEFITS OF THE SPR FROM THE STANDPOINT OF THE VARIOUS RULE ELEMENTS UNDER THE RULE ALTERNATIVES. A MATRIX TO COMMUNICATE THIS INFORMATION WITH SOME ACCOMPANYING TEXT WOULD BE INCLUDED

3.2 MAJOR ASSUMPTIONS

Macroeconomic Assumptions

The EIA's Macroeconomic Activity Module (MAM) represents the interaction between the U.S. economy as a whole and energy markets. The rate of growth of the economy, measured by the growth in GDP is a key determinant of the growth in demand for energy. Associated economic factors, such as interest rates and disposable income, strongly influence various elements of the supply and demand for energy. At the same time, reactions to energy markets by the aggregate economy, such as a slowdown in economic growth resulting from increasing energy prices, are also reflected in this module.

A detailed description of the MAM is provided in the EIA publication, Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System, DOE/EIA-M065 (2009), (Washington, DC, January 2009).

Key Assumptions

The output of the U.S. economy, measured by GDP, is expected to increase by 2.4 percent between 2008 and 2035 in the reference case. Two key factors help explain the growth in GDP: the growth rate of nonfarm employment and the rate of productivity change associated with employment. Real GDP growth slows during the first three years of the forecast, reflecting the current economic recession, shows higher growth for the first ten years as the economy recovers, and then returns to its long-run growth path.

In the reference case, real GDP declines by 0.9 percent for the first two years, and then returns to 3.0 percent growth for the recovery period and 2.5 percent growth for the final fifteen years. Both the high and low macroeconomic growth cases show similar patterns of early lower growth, recovery, and settling back into their respective long-run growth trends. In the near term from 2008 through 2010, the growth in nonfarm employment is low at -2.2 percent compared with 2.4 percent in the second half of the 1990s, while the economy is expected to experience productivity growth of 2.0 percent.

Over the projection period, nonfarm employment is expected to grow by 0.8 percent per year. Nonfarm employment, a measure of demand for nonfarm labor, is generally more volatile than the labor force, a measure of labor supply. The latter depends upon the projection of population and labor force participation rate. The U.S. Census Bureau's (USCB) middle series population projection is used as a basis for population growth for the Annual Energy Outlook (AEO) 2010. Total population is expected to grow by 0.9 percent per year between 2008 and 2035, and the share of population over 65 is expected to increase over time. However, the share of the labor force in the population over 65 is also projected to increase in the projection period.

To achieve the reference case's long-run 2.4 percent economic growth, there is an anticipated steady growth in labor productivity. The improvement in labor productivity reflects the positive effects of a growing capital stock as well as technological change over time. Nonfarm labor productivity is expected to remain between 1.9 and 2.0 percent for the remainder of the projection period from 2008 through 2035. Business fixed investment as a share of nominal GDP is expected to grow over the last 10 years of the projection. The resulting growth in the capital stock and the technology base of that capital stock helps to sustain productivity growth of 2.0 percent from the 2008 to 2035.

To reflect the uncertainty in projection of economic growth, the AEO2010 uses high and low economic growth cases along with the reference case to project the possible impacts on energy markets. The high economic growth case incorporates higher population, labor force and productivity growth rates than the reference case. Due to the higher productivity gains, inflation and interest rates are lower compared to the reference case. Investment, disposable income, and industrial production are increased. Economic output is projected to increase by 3.0 percent per year between 2008 and 2035. The low economic growth case assumes lower population, labor force, and productivity gains, with resulting higher prices and interest rates and lower industrial output growth. In the low economic growth case, economic output is expected to increase by 1.8 percent per year over the projection horizon.

EIA Coal Market Module

The National Energy Modeling System (NEMS) Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, Coal Market Module of the National Energy Modeling System 2010, DOE/EIA-M060 (2010) (Washington, DC, 2010).

Key Assumptions

Coal Production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the projection. Forty separate supply curves are developed for each of 14 supply regions, nine coal types (unique combinations of thermal grade and sulfur content), and two mine types (underground and surface). Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, the cost of factor inputs (labor and fuel), and other mine supply costs.

The key assumptions underlying the coal production modeling are:

As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80 percent range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the level of capacity utilization, the supply region, and the mining process (underground or surface). The volume of capacity expansion permitted in a projection year is based upon historical patterns of capacity additions.

Between 1980 and 1999, U.S. coal mining productivity increased at an average rate of 6.7 percent per year, from 1.93 to 6.61 tons per miner per hour. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining.[1] Since 1999, however, growth in overall U.S. coal mining productivity has slowed substantially, decreasing at a rate of 1.1 percent per year to 5.96 tons per miner hour in 2008. By region, productivity in most of the coal producing basins represented in the CMM has declined some during the past 5 years. In the Central Appalachian coal basin,

which has been mined extensively, productivity declined by a significant 33 percent between 1999 and 2008, corresponding to an average decline of 4.4 percent per year.

Over the projection period, labor productivity is expected to decline in most coal supply regions, reflecting the trend of the previous five years. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

In the CMM, different rates of productivity improvement are assumed for each of the 40 coal supply curves used to represent U.S. coal supply. These estimates are based on recent historical data and expectations regarding the penetration and impact of new coal mining technologies. [2] Data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Mine Safety and Health Administration's (MSHA) Form 7000-2, "Quarterly Mine Employment and Coal Production Report" and the Energy Information Administration's Form EIA-7A, Coal Production Report. In the reference case, overall U.S. coal mining labor productivity declines at rate of 0.3 percent a year between 2008 and 2035.

With the exception of the AEO2010 Low and High Coal Cost Cases, both the wage rate for U.S. coal miners and mine equipment costs are assumed to remain constant in 2008 dollars (i.e., increase at the general rate of inflation) over the projection period. This assumption primarily reflects the recent trends in these cost variables.

Coal Distribution

The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm.

The projected levels of coal-to-liquids, industrial steam, coking, and residential/commercial coal demand are provided by the petroleum market and industrial, commercial, and residential demand modules, respectively. Electricity coal demands are projected by the Electricity Market Module (EMM); coal imports and coal exports are projected by the CMM based on non-U.S. coal supply availability, endogenously determined U.S. import demand, and exogenously determined world coal demand (non-U.S.).

The key assumptions underlying the coal distribution modeling are:

Base-year (2008) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve. Delivered price data are from Form EIA-3, Quarterly Coal Consumption Report-Manufacturing Plants, Form EIA-5, Quarterly Coke Consumption and Quality Report, Coke Plants, Form EIA-923, Power Plant Operations Report, and the U.S. Bureau of the Census' Monthly Report EM-545. Minemouth price data are from Form EIA-7A, Coal Production Report.

For the electricity sector only, a two-tier transportation rate structure is used for regions that, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars).

Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices, calculated econometrically, are measures of the change in average transportation rates, on a tonnage basis, that occurs between successive years for coal shipments. An east index is used for coal originating from eastern supply regions while a west index is used for coal originating from western supply regions. The east index is a function of railroad productivity, the user cost of capital for railroad equipment, and national average diesel fuel price. The user cost of capital for railroad equipment is calculated from the producer price index (PPI) for railroad equipment, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10 percent), less any capital gain associated with the worth of the equipment. In calculating the user cost of capital, a risk premium is added to the cost of borrowing in order to account for the possibility that greenhouse gas (GHG) emissions may be regulated in the future. The west index is a function of railroad productivity, investment, and western share of national coal consumption. The indices are universally applied to all domestic coal transportation movements within the CMM. In the AEO2010 reference case, eastern coal transportation rates are projected to be the same in 2035 and western rates are projected to be 5 percent higher in 2035 compared to 2008.

For the projection period, the explanatory values are assumed to have varying impacts on the calculation of the indices. For the west, investment is the analogous variable to the user cost of capital of railroad equipment. The investment value and the PPI for rail equipment, which is used to derive the user cost of capital increase with an increase in national ton-miles (total tons of coal shipped multiplied by the average distance). Increases in investment (west) or the user cost of capital for railroad equipment (east) cause projected transportation rates to increase. For both the east and the west, any related financial savings due to productivity improvements are assumed to be retained by the railroads and are not passed on to shippers in the form of lower transportation rates. For that reason, productivity is held flat for the projection period for both regions. For the east for the projection period, diesel fuel is removed from the equation in order to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program. Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. While the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, recommended that the railroads agree to develop some consistencies among their disparate programs and likewise recommended closely linking the charges to actual fuel use. The STB cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.

For AEO2010, representation of a fuel surcharge program is included in the coal transportation costs. For the west, the methodology is based on Burlington Northern/Santa Fe (BNSF) Railway

Company's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon. For every $0.06 per gallon increase above $1.25, a $0.01 per carload mile is charged. For the east, the methodology is based on CSX Transportation's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $2.00 per gallon. For every $0.04 per gallon increase above $2.00, a $0.01 per carload mile is charged. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a pre-determined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate. For every projection year, it is assumed that 100 percent of all coal shipments are subject to the surcharge program.

Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2008) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by generators on the EIA-923, Power Plant Operations Report. Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization (FGD) equipment. Coal contract quantities are reduced over time based on contract duration data from information reported on the Form EIA-923, Power Plant Operations Report, historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.

Electric generation demand received by the CMM is subdivided into “coal groups” representing demands for different sulfur and thermal heat content categories. This process allows the CMM to determine the economically optimal blend of different coals to minimize delivered cost, while meeting emissions requirements. Similarly, nongeneration demands are subdivided into subsectors with their own coal groups to ensure that, for example, lignite is not used to meet a coking coal demand.

Coal-to-liquids (CTL) facilities are assumed to be economic when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities with generation capacity of 652 megawatts (MW) and the capability of producing 50,000 barrels of liquid fuel per day. The technology assumed is similar to an integrated gasification combined cycle, first converting the coal feedstock to gas, and then subsequently converting the syngas to liquid hydrocarbons using the Fisher-Tropsch process. Of the total amount of coal consumed at each plant, 46 percent of the energy input is retained in the product with the remaining energy used for conversion (38 percent) and for the production of power sold to the grid (17 percent). The liquid products produced include naphtha, kerosene, and diesel. For AEO2010, coal-biomass-to-liquids capability has been incorporated into the NEMS structure. These facilities have the same operating features as CTL plants except 80 percent of the energy input is derived from coal with the remaining 20 percent derived from biomass.

Coal Imports and Exports

Coal imports and exports are modeled as part of the CMM’s linear program that provides annual projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimize the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional world coal import demands. It does this subject to constraints on export capacity and trade flows.

The key assumptions underlying coal export modeling are:

Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.

Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

Data inputs for coal trade modeling:

U.S. coal exports are determined, in part, by the projected level of world coal import demand. Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.

Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account typical vessel sizes and route distances in thousands of nautical miles between supply and demand regions.

Coal Quality

Each year the values of base year coal production, heat, sulfur, and mercury (Hg) content and CO_2emissions for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the Form EIA-923, a survey of the origin, cost, and quality of fossil fuels delivered to generating facilities; the Form EIA-5, which records the origin, cost, and quality of coal receipts at domestic coke plants; and the Form EIA-3, which records the origin, cost, and quality of coal delivered to domestic industrial consumers. Estimates of coal quality for the export and residential/commercial sectors are made using the survey data for coal delivered to coking coal and industrial steam coal consumers.

The CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for three coal types (coking, bituminous steam, and subbituminous). It includes five U.S. export regions and four U.S. import regions.

USEPA

Coal Alternative Cases

Coal Cost Cases

In the reference case, coal mine labor productivity is assumed to decline on average by 0.3 percent per year through 2035, while miner wage rates and mine equipment costs remain constant in 2008 dollars. Eastern and Western transportation rates are flat and 5 percent higher, respectively, in 2035 compared to 2008. In two alternative coal cost cases, productivity, average miner wages, equipment cost, and transportation rate assumptions were modified for 2010

through 2035 in order to examine the impacts on U.S. coal supply, demand, distribution, and prices.

In the low mining cost case, coal mine labor productivity is assumed to increase at an average rate of 3.2 percent per year through 2035. Coal mining wages, mine equipment costs, and other mine supply costs are all assumed to be about 25 percent lower by 2035 in real terms in the low coal cost case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower by 2035.

In the high mining cost case, coal mine labor productivity is assumed to decline at an average rate of 3.0 percent per year through 2035. Coal mining wages, mine equipment costs, and other mine supply costs are assumed to be about 30 percent higher by 2035. Compared to the reference case, coal transportation rates are assumed to be 25 percent higher by 2035.

The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-user demand modules.

No Greenhouse Gas Concern Case

In the reference case, to reflect the market reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital for investments in new coal-fired power plants without carbon capture and sequestration technology and new CTL plants is assumed. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation, nor does it affect the operation of existing plants. This adjustment was first implemented for AEO2009.

The No GHG concern case excludes the 3-percentage point increase in the cost of capital.

3.3 ANALYSIS PERIOD AND EXPECTED BENEFIT AND COST ACCRUAL

Both environmental and economic benefits and costs associated with the SPR will be accrued over time, as the rule is implemented.

When adopted in final form, the stream protection rule would take effect 60 days after publication in states with federal programs and on Indian lands. Implementation in states with approved regulatory programs would take considerably more time. OSM would first notify those states under 30 CFR 732.17 that we have determined that they must amend their programs to remain no less effective than the revised federal rules. The states would respond by submitting either a proposed program amendment or, more likely, a description of amendments to be proposed together with a schedule for submission of the proposed amendments and a timetable for enactment. To avoid unnecessary disruption of state programs, OSM would generally accept schedules under which states would prepare and submit proposed amendments only after the completion of litigation of the new federal rule at the appellate level. This process can easily take 5 or more years.

Implementation Timeline

Federal Program States and Indian lands

- Rule takes effect 60 days after publication in the Federal Register.
- Permit applications approved after that date must comply with the rule.
- Existing operations would have to comply with new performance standards no later than the time of permit renewal (within 5 years).

Primacy States

- OSM will send Part 732 notifications to all states 90 days after publication of the final rule in the Federal Register. The notifications would require the states to amend their programs to be no less effective than the revised federal rules.
- Within 60 days of receipt of a Part 732 notification, the state must submit either a proposed program amendment or an action plan with a timeline for submission of such an amendment.
- Because the rule will likely be challenged in court, OSM anticipates that states will submit timelines providing for submission of proposed program amendments only after litigation is concluded, which OSM estimates will take 5 years.
- OSM anticipates that states will take 18 months to develop program amendments after the conclusion of litigation.
- OSM review and approval of state program amendments will take 7 months after submission.
- OSM anticipates that states will put the approved program amendments into effect within an average of one year from date of approval (up to 2 years in states with legislatures that do not meet every year).
    - Total Elapsed Time: 102 months (8.5 years)
- Permit applications approved after that date must comply with the amended state programs.
- Existing operations would have to comply with new performance standards no later than the time of permit renewal (within 5 years).

For this RIA, the implementation period is expected to require approximately 8.5 years. However, the costs and benefits accrual from the proposed SPR would be expected to extend well beyond 8.5 years. **(MORE TO BE ADDED)**

3.4 CAVEATS

The following caveats are offered at the beginning of this RIA in recognition of the limitations of this particular analysis, and any analytical approach designed to gauge the economic impacts (costs and benefits) of a policy being evaluated during the rulemaking process.

1. **Effective Regulatory Solutions Reflect Balance**: Policy-making processes by their very nature are about achieving goals within the realm of the possible.

In this light, this RIA recognizes that different views exist about how to accomplish the balancing act of protecting the nation's streams while ensuring that a sufficient supply of coal is available to meet the needs of communities and businesses. Stakeholders will always argue about the adequacy and accuracy of economic information used in judging a policy's future impacts. The question flowing from this consideration is: How can OSM and its state regulatory partners, working with the coal mining industry, strike the right balance between environmental protection and economic development?[16] This ultimately seems the most appropriate strategy for fulfilling OSM's mission in the context of the proposed SPR.

2. **Policy Decision-Making Occurs in an Uncertain Environment Characterized by Imperfect Information**: Science has always aspired to produce knowledge that informs and reduces uncertainty, and yet decisions, including public policy decisions, must be made in light of imperfect information and lingering uncertainty. If decision-makers were to wait for perfect information, they would never make a decision. No RIA can provide perfect economic information about a proposed policy's impact. Moreover, it is only one source of information used by policymakers in making these decisions.

3. **Forecasts of Policy Impacts Are Not Destiny**: Too often, policymakers and the experts advising them confuse forecasts for destiny. Many factors can influence whether a forecasted favorable or unfavorable outcome is attained in the future. For policies that are expected to have a significant negative impact (in terms of costs, restrictions, etc.) on certain stakeholders, in this case coal mining areas and coal mining companies, it is important that these policies be implemented carefully, allowing time to adjust to new regulatory requirements. It is also important to help businesses (coal mining companies in this case) innovate with new technologies and market strategies that achieve the policy objectives related to compliance and enforcement, and also help them reduce their compliance costs if at all possible.

4. **Compliance Cost Estimates are Often Overestimated**: It is important to recognize the findings of many earlier research studies showing that regulatory compliance costs are often significantly overestimated. According to a 2004 research paper, which examines the research on estimated and actual regulatory compliance costs by Ruth Ruttenberg and Associates: *"Federal agencies frequently overestimate the costs of their regulations. They often use poor quality data, conservative assumptions, and static analysis. Overestimates emerge — be it from OSHA's analysis of the costs of a proposed Vinyl Chloride Standard, EPA's regulation of acid rain, NHTSA's regulation of test procedures for advanced air bags, FDA's efforts to reduce the risk of an outbreak of transmissible spongiform encephalopathis, or*

[16] OSM's mission statement under SMCRA clearly calls for managing the balance between environmental protection and meeting the nation's needs for coal. Source: http://www.OSM.gov/topic/smcra/smcra.shtm. Accessed on February 15, 2011.

CPSC's cost estimate for flammable upholstered furniture. Despite concerns of industry with cost and feasibility before a standard is promulgated, the paths toward compliance predictably lead to lower cost alternatives, often far lower than predicted. Sometimes regulatory compliance even promotes increases in productivity."[17] A principal reason why regulatory compliance costs are too high is because these studies give inadequate attention to the role of the private market and technology in helping businesses and others impacted by regulations to efficiently achieve compliance at lower overall cost.

5. **RIA Analyses Should Be Viewed as Supplementary Information for Policy Decisions**: *"In most cases, regulatory impact analysis techniques provide supplementary, rather than substitute, information for policy makers. Even when taken together, Benefit-Cost Analysis (BCA) and Cost-Effectiveness Analysis (CEA) do not provide complete information about the impact of regulations. Rather, they are part of a much larger process of regulatory impact analysis used to assess the effects of federal regulations. While policy analysts typically urge that quantitative results of BCA and CEA should not be over-emphasized, decision makers often ignore this advice. Even when the results of these analyses suggest that a regulation will produce substantial net benefits, it is important to understand that, in most cases, the results will produce losers as well as winners."*[18]

6. **OMB Guidelines**: This RIA attempts to follow the OMB's guidelines for a Regulatory Impact Analysis under Circular A-4 and Section 6(a)(3)(c) of Executive Order 12866. While the U.S. OMB provides guidelines on the preparation of an RIA, wide variation exits in the content and length of RIA documents.[19] This document provides best available information about the economic costs and benefits of the proposed SPR, which in many cases is only qualitative in nature, given the difficulties in measuring many of the rule's impacts in quantitative or monetized terms.

3.5 PRIMARY DATA SOURCES AND METHODS OF ANALYSIS

1. EIA Coal Data
   a. Historical data on production, consumption, imports, exports, prices, employment, productivity etc.
   b. Forecast data on production, consumption, imports, exports, prices, employment, productivity, etc.
2. U.S. Bureau of Labor Statistics (BLS):
   a. Historical and forecast data on coal mining industry employment

[17] Ruth Ruttenberg and Associates, Inc., *NOT TOO COSTLY, AFTER ALL: An Examination of the Inflated Cost Estimates of Health, Safety, and Environmental Protection*, prepared for the Public Citizen Foundation, December 2004.

[18] AARP Public Policy Institute, *Exploring the Role of Cost-Benefit Analysis in Government Regulations*, 2007.

[19] This is evident in reviewing various RIAs produced by the Office of Surface Mining, other offices within the DOI, USEPA, and other federal agencies.

3. National Mining Association:
    a. Mining industry economic impact analysis at national and state levels.
4. Source on mining royalty data
5. Sources socioeconomic data

(TO BE EXPANDED)

The coal mining industry was analyzed using EIA data to characterize production, consumption, price, employment, productivity, import and export, and other key trends.

3.5.1 Cost-Benefit Analysis Approach

3.5.1.1 Cost-Benefit Analysis

The main method used for valuation is cost-benefit analysis (CBA). This analysis is basically compiling the costs of a project as well as the benefits, then translating them into monetary terms and discounting them over time. (Discounting is the process of determining the present value of future benefits and costs.) Ideally, only projects with benefits greater than costs would be acceptable.

Cost-benefit comparisons have some problems. First, environmental benefits often lack market value, yet their costs are known. Second, benefits are often collected over time, while costs are up front. This creates a dilemma, since the question to be answered is in present time. Third, it is often difficult to understand what is being measured or to determine values for what is being measured. Fourth, results are often controversial and in some cases, could be used against you. However, it is good to remember that you are empowered just by describing each benefit, even if you can't value it.

Cost-Benefit Analysis Definition

CBA is a term that refers to an analysis used to assess the costs and benefits of a proposed policy, program, or project. In the policy-making arena, CBA is often one of a number of sources of input used by policy makers in determining the appropriateness of a proposed policy, and whether it is worthy of adoption.

As a method to estimate future economic effects of a proposed action, CBA works best when both costs and benefits are clearly defined, and can be measured in quantitative and monetary terms. This is often not the case since many costs and benefits are immeasurable at the time a policy is initially proposed. Where these measurement difficulties exist, best available data and analysis are used to define and measure costs and benefits and professional judgment is exercised to determine whether the measures are reasonable given all constraints.[20]

Accurate measurement of the economic costs and benefits of the OSM SPR is difficult because of: 1) the proposed and evolving nature of the SPR under its various alternatives; and 2) the paucity of quantifiable technical data defining in clear terms the environmental impacts of the rule. For this reason, the RIA cannot measure many of the possible costs and benefits of the SPR elements without relying on major assumptions and best professional judgment.

[20] Farrow Scott, and Toman, Michael, *Using Environmental Cost-Benefit Analysis to Improve Government Performance,* Discussion Paper 99-11, Resources for the Future, Washington, DC, December 1998

While CBA is a required step for potentially economically significant rules (or those creating an annual cost impact of $100 million or more) by the OMB in the federal rule-making process, CBA has its proponents and critics.

Proponents of CBA make two basic arguments in its favor.[21] They first argue that use of CBA leads to more "efficient" allocation of society's resources by better identifying which potential regulatory actions are worth undertaking and in what fashion.

A second set of arguments holds that CBA would produce a better regulatory process – more objective and more transparent, and thus more accountable to the public. CBA has been offered as a means of preventing an agency from just doing anything it wants or, more invidiously, from benefiting politically favored groups through its decisions.

CBA has its critics, which say: *"Cost-benefit analysis, widely favored today as a technique for making public policy decisions, is a failure both in theory and in practice. In theory, it cannot comprehend important but priceless values, cannot escape the assumption that everything is for sale and can be traded off against everything else, and cannot accurately reflect the central role of uncertainty and the need for precaution in practice. It persistently tilts toward overstating costs, toward trivializing the future, and toward replacing clear policy debates with obscure technical quarrels."* [22]

CBA: Two Basic Approaches

There are two basic approaches to CBA: the ratio approach and the net benefit approach. The ratio approach indicates the amount of benefits (or outcomes) that can be realized per unit expenditure in various policy alternatives. In the ratio approach, a policy is cost beneficial if the ratio of the change in costs to the change in benefits is less than one.

The net benefits approach indicates the absolute amount of money saved or lost due to identified policy alternatives. In the net benefits formulation, a policy is cost-beneficial if the net change in benefits exceeds the net change in costs. Clearly, OMB guidelines call for the net-benefit approach to CBA so that is the approach taken in this RIA.

Net Benefits Approach to CBA: How It Works

In broad outline, the results of a CBA (or BCA) can be seen as a table in which the rows represent impacts (benefits or costs), and columns represent alternative regulatory actions. The costs and benefit entries are expressed in monetary terms wherever possible. Future costs and benefits are expressed in terms of today's monetary units through a procedure economists call discounting (discussed below). Since benefits and costs in practice are uncertain, the table entries also are adjusted for the probability of occurrence of the benefit or cost if the regulatory alternative is implemented.

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[21] Source: Center for Progressive Reform. Website accessed February 11, 2011. http://www.progressiveregulation.org/perspectives/costbenefit.html

[22] Critique of Cost-Benefit Analysis, and Alternative Approaches to Decision-Making: A Report to Friends of the Earth England, Wales and Northern Ireland, By Frank Ackerman, January 2008

In each column, monetized costs are subtracted from monetized benefits to obtain a "bottom line" measure of the (discounted) total net benefits across time and affected individuals. For economists, this bottom line is a key factor, though not the only one, in answering the question of whether society as a whole is better off with one regulatory alternative or another, or whether the alternative chosen is the least cost.

NOTE: Much of the information related to the quantification and monetization of economic benefits and costs related to the SPR is not available for this submission. This information will be incorporated in the RIA once the PKS team and OSM have concluded their work related to costs and benefits.

3.5.1.2 Benefits Associated with Rule and How Analyzed

MORE BENEFITS TO BE DEVELOPED WITH OSM

To estimate the benefits accrued to the proposed rule a BT methodology will be used to assess the benefits associated with avoided stream loss through linear feet and acre and the costs from the proposed restoration activities for streams covered under the existing rules. An analysis of relevant literature found values associated with many of the ecological services that are provided by streams of all orders and magnitudes and the associated riparian buffers. One of the first attempts to provide a global-scale assessment of ecological services was Costanza et al (1997), which provided estimated metrics of natural capital and ecosystem services. This article has been cited throughout the literature as one of the primary articles of its type. It has been criticized for its approach on scope and scale; however, its overall contribution to the field has not been found lacking. More recently, Ingraham and Foster (2008) provided the value of ecosystem services provided by U.S. National Wildlife Refuge System lands. Similar to Costanza et al. (1997), Ingraham and Foster (2008) provided a compilation of services into a metric by ecosystem type. Between these two pieces of peer-reviewed literature, an upper bound on the potential value per acre of stream impacts avoided can be estimated.

Table 3-3: Benefit Transfer Values

Ecosystem Type	Costanza et al (1997)	Ingraham & Foster (2008)	Average
	($US 2008/acre)		
Temperate Forests	$177	$850	$514
Grass/Rangelands	$136	$51	$94
Wetlands	$8,679	$8,800	$8,740
Lakes/River/Open Water	$4,989	$290	$2,640

For a lower bound, AC s for restoration of streams can be estimated. This lower bound would use the work of Baker (2008) with data for woody species and herbaceous species-related reclamation efforts for coal mines in Appalachia; the work of Bonham and Stephenson (2004) for linear foot estimate cost for stream restoration activities in Southern Appalachia; and the Environmental Law Institute (2007) average estimate linear foot costs for stream restoration across all U.S. Army Corps of Engineers district. Table 3-3 is a summary of upper and lower values used for evaluating benefits. As available, supplemental data from operating mitigation banks across the United States would also be used, if linear foot estimates for cost can be

determined through an interview with mitigation bank sponsors or mitigation bank credit brokers. The average per acre cost for forestry reclamation activities, according to Baker (2008) was $1,647 per acre and for herbaceous (hayland/pastureland) the reclamation cost was $1,831 per acre. Stream restoration per linear foot was estimated by the Environmental Law Institute to be $240 per linear foot. Bonham and Stephenson (2004) estimated that for small projects (less than 3,000 linear feet) the average cost for stream restoration was $119 per linear foot. Cost per linear foot declines as the amount of stream restoration in a project increases.

3.5.1.3 Costs Associated with Rule and How Analyzed

Industry costs, compliance costs, social costs.

COST ELEMENTS AND METRICS TO BE DEVELOPED WITH OSM

3.5.2 Supporting Analysis

3.5.2.1 Regulatory Flexibility Act (Small Business Impact) Analysis

3.5.2.1.1 Purpose

This section presents and analyzes best available information on the economic impact of the OSM's proposed SPR on small coal mining business entities. Available data from various sources have been examined and analyzed. This analysis is a part of the rule's Conceptual RIA. A more complete analysis of these impacts will be conducted within the Final RIA on the Final SPR when it exists.

3.5.2.1.2 Background and Definitions

An analysis of the economic impact of proposed federal regulations on small business entities (also known as firms, companies, or enterprises) is a required component of a (RIA. Executive Order 13272, signed August 13, 2002, gave federal agencies new direction in their efforts to assess the impact of their proposed rulemakings on small businesses and other small organizations under the Regulatory Flexibility Act (RFA). It also directed the U.S. Small Business Administration's Office of Advocacy to provide agencies with information on how to comply with the President's directive.

By definition, the RFA is an effort by the federal government to balance the social goals of federal regulations with the needs and capabilities of small businesses and other small entities in American society.

Research indicates that smaller businesses bear a greater proportionate share of the burden of regulatory compliance costs. For firms employing fewer than 20 employees, the annual regulatory burden averaged $6,975 per employee during the 1995-2000 time period—almost 60 percent more than that of firms with more than 500 employees.[23] Small businesses, defined as firms employing fewer than 20 employees, bear the largest burden of federal regulations, according to available research.

[23] See W. Mark Crain and Thomas D. Hopkins, The Impact of Regulatory Costs on Small Firms, report no. PB2001-107067, prepared by Hopkins and Crain for the U.S. Small Business Administration, Office of Advocacy (Springfield, Va.: National Technical Information Service, 2001).

As of 2008, small businesses (firms with less than 500 employees) faced an annual regulatory cost of $10,585 per employee, which was 36 percent higher than the regulatory cost facing large firms (defined as firms with 500 or more employees).[24]

Since the federal government began calculating the economic impact of the RFA in 1998, the law is estimated to have saved small entities (and the U.S. economy as a whole) more than $200 billion without undermining the broad purposes of the regulations it affects.[25]

3.5.2.1.3 Definition of a Small Coal Mining Business

The U.S. Small Business Administration (SBA) defines a small business in the coal mining industry (North American Industry Classification Code System [NAICS] 2121) for RFA purposes as an entity employing fewer than 500 people.[26] While this definition is used in assessing the economic impact of the SPR on smaller coal mining entities, a more complete analysis of the coal mining industry by various employment size groups is provided.[27]

3.5.2.1.4 U.S. Coal Mining Industry Enterprise (Corporate) Profile

For RFA purposes, the coal mining industry is analyzed from two perspectives: 1) enterprise (corporate) basis, and 2) establishment (operating facility) basis. Because of differences in how the data are organized and reported, the two sets of numbers do not align completely, but they are close. *The most important data in fulfilling the RFA requirements is the corporate or enterprise data.*

Table 3-4 analyzes the U.S. coal mining industry on an enterprise basis, identifying the number of firms, establishments, and employment for coal mining, or NAICS 2121. An **establishment** is defined as a single physical location at which business is conducted or where services or industrial operations are performed. An **enterprise** is defined as a business organization consisting of one or more domestic establishments under common ownership or control. For companies with only one establishment, the enterprise and the establishment are often the same. The employment of a multi-establishment enterprise is determined by summing the employment of all associated establishments.

Table 3-4: U.S. Coal Mining Industry Enterprise Profile in 2007[28]

Enterprise Employment Size	Number Firms	Number Establishments	Employment	% Total Firms	% Total Establishments	% Total Employment
0-4	197	199	332	29.0	18.7	0.4

[24] See Nicole Crain and W. Mark Crain, The Impact of Regulatory Costs on Small Firms, for the U.S. Small Business Administration, Office of Advocacy under contract number SBAHQ-08-M-0466, September 2010.

[25] Source: Analysis of Regulatory Flexibility Act (RFA) annual reports by the United States Small Business Administration on November 30, 2010 at: http://www.sba.gov/advo/laws/flex/

[26] U. S. Small Business Administration, Table of Small Business Size Standards Matched to North American Industry Classification System Codes, Update, November 5, 2010.

[27] NAICS stands for the North American Industry Classification System, which standardizes how operating businesses are classified for operating and government reporting purposes.

[28] Source: U.S Census, Statistics of U.S. Business Enterprises, 2007.

5-9	80	80	527	11.8	7.5	0.7
10-19	103	105	1,433	15.2	9.8	1.8
<20	380	384	2,292	56.0	36.0	2.9
20-99	194	215	8,284	28.6	20.2	10.4
100-499	64	142	12,392	9.4	13.3	15.5
<500	638	741	22,968	94.0	69.5	28.8
500+	41	325	56,880	6.0	30.5	71.2
Total	679	1,066	79,848	100.0	100.0	100.0

The U.S. coal mining industry in 2007, analyzed on an enterprise (firms) basis, consisted of 679 total firms, or corporate entities, which operated 1,066 mining operations employing 79,848 people. Approximately 56% of the industry's total firms had 20 or fewer employees and 94% had less than 500 employees.

On an employment basis, only 2.9% (2,292 jobs) of coal mining enterprise employment was accounted for by coal enterprises with less than 20 employees. Coal enterprises with employment less than 500 people accounted for 29% of total employment, while coal enterprises with more than 500 employees represented 71% of total employment.

3.5.2.1.5 U.S. Coal Mining Industry Revenues by Small and Large Businesses

Table 3-5 analyzes coal revenues produced by small and large coal mining businesses.

Table 3-5: Coal Mining Receipts (Revenues) by Small and Large Businesses in 2007[29]

Industry Receipts Size Group (Dollars)	Firms	Employ.	Estimated Receipts ($000)	Avg. Firm Employ. Size	Avg. Firm Receipts ($000)	No. Firms with Avg. Employ <500	% Industry Total Receipts
Total	679	79,848	33,550,214	118	49,411	620	100.0%
<100,000	24	0	0	0	0	24	0.0%
100,000-499,999	278	2,092	105,063	8	378	278	0.3%
500,000-999,999	25	80	16,473	3	659	25	0.0%
1,000,000-2,499,999	40	518	71,559	13	1,789	40	0.2%
2,500,000-4,999,999	50	1,294	184,756	26	3,695	50	0.6%
5,000,000-7,499,999	44	1,422	275,296	32	6,257	44	0.8%
7,500,000-9,999,999	27	1,146	236,338	42	8,753	27	0.7%
10,000,000-14,999,999	47	2,336	590,449	50	12,563	47	1.8%
15,000,000-19,999,999	18	1,107	323,721	62	17,985	18	1.0%
20,000,000-24,999,999	11	819	254,100	74	23,100	11	0.8%
25,000,000-29,999,999	9	935	225,935	104	25,104	9	0.7%
30,000,000-34,999,999	5	462	142,363	92	28,473	5	0.4%
35,000,000-39,999,999	7	548	250,861	78	35,837	7	0.7%

[29] Source: U.S Census, Statistics of U.S. Business Enterprises, 2007.

40,000,000-44,999,999	2	0	0	0	0	2	0.0%
45,000,000-49,999,999	3	0	0	0	0	3	0.0%
50,000,000-74,999,999	24	3,512	1,444,888	146	60,204	24	4.3%
75,000,000-99,999,999	6	NA	NA	NA	NA	6	NA
100,000,000+	59	61,596	28,810,646	1,044	488,316	0	85.9%
% Defined as Small Business (<500 Employees)	91.3%						
% Industry Receipts by Small Businesses	14.1%						

The data in Table 3-4 indicates that 14.1% of the coal mining industry's total receipts (revenues) in 2007 was produced by coal firms employing less than 500 people, or small businesses. The remaining 85.6% of industry receipts come from coal firms that employ 500 or more employees, or large businesses.

3.5.2.1.6 U.S. Coal Mining Industry Business Legal Form Profile

The analysis in Table 3-5 indicates that on an establishment basis over 48% of total coal mining business establishments (operations) employed less than 20 people and almost 98% employed less than 500 people. Only 2.3% of all coal mining establishments employed over 500 people in 2008 according to the data in Table 3-6.

Almost 78% of all coal mining establishments are associated with corporations or S-corporations, and the other 22% are associated with sole proprietorships and partnerships, which tend to be smaller in employment size than corporate entities.

Table 3-6: U.S. Coal Mining Industry Business Legal Form Profile, 2008[30]

Business Legal Type	Total Establish	<20 Employ	20-499 Employ	>500 Employ	% <20 Employ	% 20-499 Employ	% >500 Employ	Totals
All Establishments	1108	536	547	25	48.4%	49.4%	2.3%	100.0%
Corporations	546	214	221	240	39.2%	57.3%	3.5%	100.0%
S-Corporations	318	172	164	169	54.1%	45.6%	0.3%	100.0%
Sole Proprietorships	44	33	19	11	75.0%	22.7%	2.3%	100.0%
Partnerships	198	117	86	79	59.1%	38.9%	2.0%	100.0%
Other	2	0	1	1	0.0%	100.0%	0.0%	100.0%

3.5.2.1.7 Coal Production and Revenues by Mine Type and Employment Size

The MSHA within the U.S. Department of Labor (USDOL) classifies establishments (mines) in the U.S. coal mining industry into three major coal commodity groups: bituminous, lignite, and anthracite.[31]

[30] U.S. Census, County Business Patterns 2008

Bituminous operations represent approximately 97% of coal mining operations and approximately 99% of coal miners and total coal production. Anthracite operations represent approximately 2% of coal mining operations and less than 1% of coal miners and total coal production. Lignite operations represent less than 1% of coal mining operations, coal miners, and total coal production.

The U.S. surface coal mining industry produced an estimated 742.5 million short tons in 2009. The average price of coal in surface mines in 2009 was $22.35 per short ton. The U.S. underground coal sector produced an estimated 332 million short tons in 2009. The average price of coal in underground mines in 2009 was $51.35 short per ton. Table 3-7 below presents the coal production and revenues for 2009.

A diligent effort was made to acquire firm or corporate level data on coal production and revenues from MSHA, but it is not available since employment data are not included in the agency's corporate data files. Employment data at the mine (establishment) level are available in the MSHA database, which were used in Table 3-6 to analyze coal production and revenues by the employment size of mines. Because of data reporting problems, mine (establishment) production and revenue data could not be aggregated at the firm or corporate level in a valid way.

Table 3-7: Coal Production by Mines in Short Tons and Coal Revenues in 2009

Coal Production by Mines in Short Tons			
Mine Size	Coal-Surface	Coal-UG	Total
1-19 Employees	19,713,676	5,036,046	24,749,722
20-499 Employees	475,066,642	236,566,737	711,633,379
500+ Employees	247,760,869	90,256,010	338,016,879
Grand Total	742,541,187	331,858,793	1,074,399,980
Total Coal Revenues, Apportioned by Coal Tonnage Produced			
Mine Size	Coal-Surface	Coal-UG	Total
1-19 Employees	$440,600,659	$258,600,962	$699,201,621
20-499 Employees	$10,617,739,449	$12,147,701,945	$22,765,441,394
500+ Employees	$5,537,455,422	$4,634,646,114	$10,172,101,536
Grand Total	$16,595,795,530	$17,040,949,021	$33,636,744,551

Source: MSHA Employment and Production Database

Over 66% of total coal production (including both surface and underground mined) in 2009 was produced by mines with employment in the 20-499 range, which are considered to be small businesses. Almost 69% of total coal production occurred in mining operations with less than 500 employees. About 2% of total coal revenues was produced by mines with less than 20 employees.

3.5.2.1.8 Coal Production Concentration

According to UEIA industry survey data, U.S. coal production is highly concentrated. The five largest corporate producers represent over 53% of total coal production in 2009, according to the

[31] This categorization is based on MSHA-collected data grouped by SIC code description. Some publications of the U.S. Department of Energy further divide the bituminous group into bituminous coal and sub-bituminous coal.

data presented in Table 3-8 below. The 29 coal producers listed in Table 3-8 account for over 87% of total U.S. coal production.

Table 3-8: Largest U.S. Coal Producers in 2009

Rank	Controlling Company Name	Production (Thou. Short Tons)	Percent of Total Production
1	Peabody Energy Corporation	189,232	17.6
2	Arch Coal Inc.	148,061	13.8
3	Cloud Peak Energy	90,965	8.5
4	Alpha Natural Resources LLC	83,523	7.8
5	CONSOL Energy Inc.	58,145	5.4
6	Massey Energy Co.	37,161	3.5
7	NACCO Industries Inc.	31,085	2.9
8	Patriot Coal Corp.	29,268	2.7
9	Peter Kiewit Sons Inc.	27,136	2.5
10	Alliance Resource Operating Partners LP	25,874	2.4
11	Murray Energy Corp.	25,837	2.4
12	Westmoreland Coal Co.	24,266	2.3
13	Energy Future Holdings Corp.	21,272	2.0
14	Drummond Co. Inc.	19,964	1.9
15	Intl Coal Group Inc. (ICG)	17,414	1.6
16	BHP Billiton Ltd.	14,917	1.4
17	James River Coal Co.	9,855	0.9
18	Chevron Corp.	9,841	0.9
19	PacifiCorp	9,447	0.9
20	Level 3 Communications	8,392	0.8
21	Walter Industries Inc.	7,571	0.7
22	Trinity Coal Corp.	6,805	0.6
23	Booth Energy Group	6,506	0.6
24	Cline Group	6,497	0.6
25	TECO Energy Inc.	6,205	0.6
26	Rosebud Mining Co.	6,084	0.6
27	Black Hills Corp.	6,016	0.6
28	Oxbow Carbon & Minerals Holding Inc.	5,703	0.5
29	Western Fuels Association Inc.	5,234	0.5
	Subtotal	**938,276**	**87.3**
	All Other Coal Producers	**136,647**	**12.7**
	U.S. Total	**1,074,923**	**100.0**

Source: EIA, U.S. Department of Energy, 2010 Annual Coal Outlook Report, May 2010

3.5.2.1.9 Earlier Relevant RFA Analyses

A preliminary RFA analysis was conducted for OSM's Excess Spoil; SBZ; Diversions Rule in 2008. The analysis did not find any major economic impacts of that rule on small mining operations and companies. The cost impact of the rule was estimated at $240,000, which was related to increased monitoring and reporting requirements created by the rule.

3.5.2.1.10 Major Observations and Summary

1. Research suggests that small businesses are generally impacted in a significant economic way by federal regulations. For this reason, it is important to carefully consider the economic impacts of the SPR on smaller coal mining companies.
2. The U.S. coal mining industry is represented by a large and significant number of small businesses, defined as those employing less than 500 people. The U.S. coal mining industry in 2007, analyzed on an enterprise (company) basis, consisted of 679 total firms, or corporate entities, which operated 1,066 mining operations employing 79,848 people. Almost 56% of the industry's total firms had 20 or fewer employees and 94% had less than 500 employees.
3. In 2007, 14.1% of the coal mining industry's total receipts (revenues) was produced by coal firms employing less than 500 people, or by small businesses. This amounts to revenues of $4.73 billion. The remaining 85.9% ($28.8 billion) of industry receipts come from coal firms that employ 500 or more employees, or large businesses. See Table 3-9.
4. Analyzed on an establishment (mine operations) basis, over 48% of total coal mining business establishments employed less than 20 people and almost 98% employed less than 500 people.
5. On an employment basis, only 2.9% (2,292 jobs) of coal mining enterprise employment is accounted for by coal enterprises with less than 20 employees. Coal enterprises with employment less than 500 people accounted for 28.8% of the industry's total employment, while coal enterprises with more than 500 employees represented 71.2% of the industry's total employment. This indicates that coal employment is heavily concentrated in larger coal mining enterprises or companies and not in smaller ones.
6. According to the economic analysis for the RIA, the baseline (pre-SPR) national economic impact (industry output) of the coal mining industry is presently $48.7 billion. This economic impact generates a total national employment impact of 182,785 jobs. If coal mining enterprises employing less than 500 people account for 28% (22,968) of the coal industry's direct employment (79,848 jobs), then it is fair to assume that coal mining enterprises with less than 500 employees also account for 28% of the industry total economic and employment impacts. This means that currently (in the pre-SPR environment) smaller coal enterprises account for an estimated $13.6 billion of the industry's total national economic impact and an estimated 51,180 of the industry's total employment impact.

7. The economic analysis for the RIA shows that under Economic Impact Analysis Scenario One (which corresponds to the EIS Alternative 5 or the proposed preferred alternative) the national economic impact of the coal industry would be reduced by $1.36 billion over a 12-year period, which represents a 2.8% overall reduction in the industry's economic impact. On an annual basis over the 12 years, this represents a $113.3 million reduction in coal mining industry economic output. It is also estimated that 5,567 jobs would be lost nationally over the 12 years under RIA Scenario One (EIS Alternative 5) as a result of this $1.36 billion economic output reduction. On an annual basis, this represents a 464-job loss per year over the 12 years. If we assume that smaller coal mining enterprises would experience equal reductions in their economic impact (-2.8%) and employment impact (-3.0%), then the economic contribution of smaller mining enterprises would be reduced by $380 million ($13.6 billion x .028) over the 12 years ($31.7 million per year), and the employment contribution of these operations would be reduced by 1,530 jobs (51,000 jobs x .030) over the 12 years, or by 128 jobs per year. Table 3-10.

8. We are unable to estimate the economic impact of the Most Stringent Alternative (EIS Alternative 5) because of insufficient data to conduct this analysis. It is known from a recent mining engineering forecast for the EIS that Alternative 5, if adopted, could trigger a 100% loss (814 million tons) of surface mining production across the United States. Using MSHA data, we estimate that surface mining operations account for 69% (743 million tons) of total coal production. Moreover, 67% of all surface mining production is accomplished by small coal mining operations (with less than 500 employees). From this standpoint, the economic impact of Alternative 2 on small mines and small mine enterprises would be catastrophic in nature. It could eliminate all of them.

9. Using the 2008 Excess Spoils and Stream Buffer Rule as the Least Stringent Alternative, we know the economic impact of the 2008 rule was expected to be minimal or insignificant from an economic impact standpoint. The economic impact of the 2008 rule was assessed to be minimal in its RFA analysis.

10. The overall conclusion of this analysis is that: a) smaller coal mining companies could be economically impacted in a catastrophic way by the EIS Alternative 5 (Most Stringent Version), if it is adopted; b) they would be impacted in an economically significant way by EIS Alternative 2 (Proposed Preferred Rule Version); and c) smaller coal mining businesses would not be impacted in any economically significant way by the baseline situation, which is represented by the 2008 Rule, which was not implemented upon its adoption.

Table 3-9: Small Business Profile Summary[32]

Coal Companies	Business Size Definition[33]	Number Firms	% Total Firms	% Total Industry Employment Total: 79,848	%Total Industry Revenues Total: $33.6 Billion	%Total Industry Production Total: 1.074 billion tons
Small Businesses	<500 Employees	638	93.9%	28.8%	14.1%	68.5%
Large Businesses	>500 Employees	41	6.1%	71.2%	85.9%	31.5%
Totals		679	100%	79,848	100%	100%

Table 3-10: Small Business Impact Summary

Impact	Proposed Rule	Most Stringent Rule	Baseline
Reduced Total Economic Output Impact (Over 12 years)	-$380 Million	Devastating impact on small mining companies. 100% elimination of surface mining across the U.S.	No significant economic impact on small mining companies
Reduced Annual Economic Output Impact $380 million/12 years)	-$31.7 Million		
Reduced Total Employment Impact (Over 12 years)	-1,530 Jobs		
Reduced Annual Employment Impact (1,530/12 years)	-128 Jobs		

(Coal Industry Analysis, EIS inputs, OSM Information Cost Burden Analysis, IMPLAN modeling, other)

3.5.2.2 Information Cost Burden Analysis

As a requirement of the Federal Paperwork Reduction Act, OSM conducted a survey to reflect the cost for coal mine operators (Operators) and SRAs to meet the information requirements of the SPR.

These direct cost impacts are summarized in Table 3-11. A more detailed summary of these impacts is provided in Appendix 3: Information Cost Burden Analysis of the SPR.

It is expected that the total cost to meet these information requirements will be $142.4 million at the time of the final rule's full implementation. This is a one-point in time cost estimate. Over 84

[32] All data are for firms or companies except the production data, which relates to mines or business establishments
[33] Reflects the U.S. SBA size standards for the coal mining industry, which must be used in the RFA analysis for the SPR.

percent ($130 million) of these costs will fall upon coalmine operators and the other 16 percent ($12.8 million) on state regulatory authorities.

Table 3-11: Information Cost Burden Impact Analysis Summary

30 CFR Sections	Type of Respondent	Programmatic Changes - Hours	Programmatic Changes - Hours x Wage Costs	Programmatic Changes - Non-Wage Costs	Programmatic Changes - Wage + Non-Wage Costs
Operator/SRA Total	Operators	246,959	$12,594,909	$116,965,818	$129,560,727
	SRA	238,573	$12,882,942	0	$12,882,942
Total		485,532	$25,477,851	$116,965,818	$142,443,669

3.5.2.3 Coal Production Shift Analysis

TO BE DEVELOPED Appendix 4

4 Economic and Coal Mining Industry Overview

4.1 BASELINE COAL MINING SITUATION – DISTRIBUTIONAL ISSUES IN U.S. COAL PRODUCTION

4.1.1 Companies

The U.S. coal-mining industry includes approximately 600 mining companies and approximately 250 exploration and mining support companies, which have combined annual revenues of approximately $50 billion. As shown in Table 4-1, major coal companies include Peabody Energy, Rio Tinto Energy America, Arch Coal, Foundation Coal, CONSOL Energy, and Massey Energy.

Table 4-1: Largest Coal-Producing Companies in the United States

Rank	Company Name	Production (thousand short tons)	Percent of Total Production
1	Peabody Energy Corp.	200,752	17.1
2	Rio Tinto Energy America	140,818	12.0
3	Arch Coal, Inc.	134,017	11.4
4	Foundation Coal Corp.	69,366	5.9
5	CONSOL Energy, Inc.	63,806	5.4
6	Massey Energy Co.	40,151	3.4
7	Patriot Coal Corp.	33,317	2.8
8	NACCO Industries, Inc.	29,554	2.5
9	Westmoreland Coal Co.	29,275	2.5
10	Peter Kiewit Sons, Inc.	28,198	2.4
11	Alliance Resource Operating Partners LP	26,395	2.3
12	Murray Energy Corp.	26,059	2.2
13	Energy Future Holdings Corp.	23,307	2.0
14	Alpha Natural Resources LLC	20,879	1.8
15	CG	18,340	1.6
16	BHP Billiton Ltd.	15,952	1.4
17	Chevron Corp.	10,976	0.9
18	PacifiCorp	10,884	0.9
19	James River Coal Co.	10,583	0.9
20	Level 3 Communications	10,559	0.9
21	Trinity Coal Corp.	8,859	0.8
22	Walter Industries, Inc.	7,471	0.6
23	Wexford Capital LLC	6,726	0.6
24	Booth Energy Group	6,621	0.6
25	TECO Energy, Inc.	6,327	0.5
26	Cline Group	6,088	0.5
27	Black Hills Corp.	6,016	0.5
28	Energy Coal Resources, Inc.	5,999	0.5

Rank	Company Name	Production (thousand short tons)	Percent of Total Production
29	Western Fuels Association, Inc.	5,261	0.4
	Subtotal	1,002,556	85.6
	All Other Coal Producers	169,253	14.4
	U.S. Total	1,171,809	100.0

Source: EIA. 2008. 2008 annual coal report.

From a coal production standpoint, the industry is highly concentrated, with the top 10 companies accounting for two-thirds of all coal production. The top three companies represent 40 percent of U.S. coal production.[34]

4.1.2 Coal Production[35]

According to preliminary data from EIA, and as shown in Table 4-2, coal production in the United States in 2009 decreased to a level of 1,072.8 million short tons, a decline of 8.5 percent, or 99.1 million short tons below the 2008 record level of 1,171.8 million short tons.

Table 4-2: Coal Production in the United States

Area	2005	2006	2007	2008	2009	2005-2009 % Change
Production by Region						
Appalachia	396.7	391.2	377.8	390.2	339.3	-14.47
Northern Appalachia	140	136.2	132.1	135.6	126.5	-9.64
Central Appalachia	235.3	236.1	226.2	234	194	-17.55
Southern Appalachia	21.3	18.8	19.3	20.6	18.7	-12.21
Interior	149.2	151.4	146.7	146.6	146.8	-1.61
Western	585	619.4	621	633.6	584.5	-0.09
Refuse Recovery	0.7	0.8	1.2	1.4	2.1	200.00
Total	1,131.50	1,162.80	1,146.60	1,171.80	1,072.80	-5.19

Source: EIA. 2009. U.S. coal supply and demand review, 2009.

In 2009, U.S. coal consumption decreased in all sectors while total coal stocks increased for the year. Coal consumption in the electric power sector in 2009 was lower by 10.0 percent, while coking coal consumption decreased by 30.6 percent and the other industrial sector declined by 16.6 percent.

The commercial and institutional sector (which before 2008 had been called “residential and commercial”), the smallest of all the coal-consuming sectors, declined by 8.4 percent in 2009. All percentage change calculations are at the short-tons level. U.S. coal exports fell from the 2008 levels, while coal imports decreased for the second consecutive year.

Overview

[34] EIA. 2008. Table 10: Major U.S. Coal Producers in 2008.
[35] Based heavily upon EIA data, analysis, and reports.

EIA's data indicate a steady shift away from Eastern coal supplies and growing reliance on Western supply sources. This shift has been under way for some time and is motivated by many factors, including the cleaner quality of Western coal and the faster growth of Western coal markets than those in the East.

U.S. coal production decreased considerably in 2009, dropping by 8.5 percent to 1,072.8 million short tons, 99.1 million short tons less than the 2008 production total. The decline in coal production in 2009 was the largest percent decline since 1958 (when production declined by 16.7 percent) and the largest tonnage decline since 1949 (when production declined by 176.1 million short tons).

Although total U.S. coal production was lower in 2009, one of the three coal-producing regions had a slight increase in coal production, while the other two had large declines. Aside from refuse production, the Appalachian and Western Regions had decreases in their respective 2009 production levels of 13.0 percent and 7.7 percent, while the Interior Region remained essentially unchanged. The decrease in the Appalachian Region production was 50.9 million short tons, while the decrease in Western Region production in 2009 was 49.1 million short tons. Coal production in the Interior Region increased, but by only 216 thousand short tons.

Appalachian Region

Coal production in the Appalachian Region ended 2009 at 339.3 million short tons, a decrease of 13.0 percent, or 50.9 million short tons, its lowest level in almost 50 years. The decline was primarily driven by the domestic and international economic situation, combined with the lower natural gas prices that prevailed during most of the year. The decrease in U.S. coal exports, which are predominantly produced in this region, helped to hold down the 2009 production. The drop in demand for coal by all the domestic coal-consuming sectors, combined with the increasing coal stock level at electric power plants, also influenced coal production for the year. Ohio was the only state in the Appalachian Region that had an increase in coal production in 2009, and one of only eight states in the nation to have a higher level of coal production for the year.

Coal production in Ohio in 2009 increased by 1.2 million short tons, or 4.5 percent, to end the year at 27.4 million short tons, the highest level in a decade. Although numerous mines in the state had lower production in 2009, including one mine that had a drop of 0.8 million short tons, increases at other mines more than offset these decreases. The majority of the 2009 increase in production was a result of higher production levels at four mines and the opening of one new mine in the state. Ohio Valley Coal's Powhatan No. 6 mine had an increase of 0.9 million short tons in 2009, while Harrison Resources' Sexton No. 2 mine and Oxford Mining's Rice No. 1 mine each had an increase in their production levels of 0.5 million short tons. Ohio American Energy's Salt Run mine had an increase of 0.4 million short tons in 2009, and Gatling Ohio's Yellowbush mine produced a total of 0.3 million short tons in its first year of production.

West Virginia, the largest coal-producing state in the Appalachian Region and the second largest in the United States, had the largest tonnage decline in the region in 2009, decreasing by 21.1 million short tons. This ended the year with a total of 136.7 million short tons, which is 13.4 percent below the 2008 level and the lowest level since 1993, when a prolonged miners' strike affected coal production.

In 2009, there were 17 mines in West Virginia that had a decrease in their respective production levels of at least 0.5 million short tons. Two of the 17 mines were abandoned – Patriot Coal's Europa mine and Arch Coal's Coal Mac No. 68 mine – while the others were idled for some portion of the year as coal operators tried to balance their supply to consumers' decreasing demand.

Fourteen of the 17 mines were located in the southern portion of West Virginia, which is classified as part of the Central Appalachian Region as identified by the coal industry. On a positive note for 2009 coal production in West Virginia, there were six mines that had an increase of at least 0.7 million short tons over their 2008 levels and one new mine – Patriot Coal's Hill Fork mine – that produced 0.7 million short tons. Two of the mines with higher production levels – Consol Energy's Loveridge No. 22 mine and Patriot Coal's Federal No.2 mine – are in Northern West Virginia, which is considered part of Northern Appalachia. The other four mines with the increased production level – Massey Energy's Slabcamp mine, Republic mine, Upper Big Branch, and Arch Coal's Coal Mac Holden No. 22 mine – are located in Southern West Virginia.

Eastern Kentucky, which is identified as part of Central Appalachia, produced 73.4 million short tons of coal in 2009, a decrease of 18.7 percent or 16.9 million short tons below the 2008 level and its lowest production level since the early 1970s. In 2009, there were seven mines in Eastern Kentucky that had a decline of 0.5 million short tons or more for the year. They were Kentucky Fuel Corporation's Bent Mountain mine, Consol Energy's Jones Fork mine, Massey Energy's Mine No. 1, Frasure Creek Mining's LLC F-2 mine, Alpha Natural Resources' Big Branch mine, Revelation Energy's S-1 Hunts Branch mine, and Miller Brothers Coal's Black Diamond mine. However, in 2009, there were also two mines in Eastern Kentucky that had increases in their coal production levels of 0.5 million short tons or more. They were Alpha Natural Resources' Mine No. 9A and Big Branch West mine. There was also one new mine that had 0.5 million short tons of production in 2009: Massey Energy's MTR Wolf Creek mine.

Pennsylvania produced 58.1 million short tons, a decrease of 11.2 percent from 2008 or 7.3 million short tons, its lowest level in more than 100 years. While the two largest mines in the state – Consol Energy's Enlow Fork mine and Bailey mine (also the two largest underground mines in the United States) – produced in 2009 at approximately the same level as 2008, declines by many other mines resulted in Pennsylvania's coal production dropping for the year.

In 2009, there were declines in coal production of at least 0.5 million short tons by four mines in Pennsylvania. The largest decline at a mine in Pennsylvania was 1.8 million short tons at Consol Energy's Blacksville No. 2 mine, which was idled for a time during the year. This mine is classified by the MSHA as a West Virginia mine, which is where the mine first produced coal. EIA classifies it as a Pennsylvania mine because the mine has progressed north from its opening portal and the coal that is currently being mined is under the Commonwealth of Pennsylvania. There was also a decrease in production of 1.3 million short tons at Consol Energy's Mine 84 as it was placed into nonproducing status during the latter part of 2009. Decreases in coal production of 0.8 million short tons and 0.5 million short tons for the year at Alpha Natural Resources' Emerald No. 1 and Cumberland mines, respectively, also contributed to the decline in coal production experienced in Pennsylvania in 2009.

Coal production in Virginia decreased in 2009 by 4.2 million short tons to a total of 20.5 million short tons, a decline of 17.0 percent and its lowest level since the mid-1950s. Four mines accounted for more than 40 percent of the decrease in coal production for the year in the state.

Consol Energy's Buchanan mine had the largest decrease of any mine in the state, a drop of 0.7 million short tons as a result of a short-term idling to help balance supply with the lower demand due to the economic downturn. The other three mines were A&G Coal Corporation's Sigmon Strip No. 23, Sawmill Hollow No. 1 mine, and Guest Mountain Mining's Mine No. 3, which had decreases in production of 0.5 million short tons, 0.3 million short tons, and 0.4 million short tons, respectively. However, there were increases in coal production at two mines that began operating during 2008 and increased production by 0.3 million and 0.4 million short tons in 2009, while one new 2009 mine produced 0.4 million short tons.

In 2009, coal production in Alabama totaled 18.8 million short tons, 8.9 percent lower than the 2008 level. Although there was an increase of 0.5 million short tons at Jim Walter Resources' No. 7 mine, decreases at most of the other mines in the state brought overall production down for the year. Declines of 0.5 million short tons that occurred at Drummond Company's Shoal Creek mine and Jim Walter Resources' No. 4 mine were the largest for the state. Declines in total coal production in 2009 were experienced by Maryland and Tennessee, which ended the year at 2.3 million short tons and 2.1 million short tons, respectively.

Interior Region

Coal production in the Interior Region in 2009 was 146.8 million short tons, comparable to the 2008 production level. The Interior Region was the only one of the three major U.S. coal supply regions to not have a decrease for the year. While the total coal production for the region was basically unchanged, that was not the case when it came to the respective states' production levels in 2009. Three of the four largest coal-producing states (Illinois, Indiana, and Western Kentucky) in the region had increased levels of production levels in 2009 compared to 2008. The other large coal-producing state in the Interior Region, Texas, had a decrease in its production level, which resulted in it falling from the number 1 coal-producing state in the Interior Region to number 2.

Western Kentucky had the largest increase in coal production in the Interior Region in 2009, increasing by 2.6 million short tons to reach a total of 32.7 million short tons. This is the fifth consecutive year that Western Kentucky experienced growth in coal production, and the 2009 increase of 8.8 percent was primarily a result of the opening of four new mines during the year. The opening of Armstrong Coal's Parkway and Eastfork mines, as well as River View Coal's River View Mine and Oxford Mining's KO mine, added 2.3 million short tons of coal to the annual total.

Coal production in 2009 in Illinois increased by 2.6 percent to end the year at a total of 33.8 million short tons. Although there was almost a 1-million-short-ton drop in coal production at Peabody Energy's Vermillion Grove mine, which was idled during the first part of the year, and a decrease of 0.5 million short tons at Knight Hawk Coal's Creek Paum mine, the increase in production of 1.0 million short tons by American Coal Company's Galatia mine and an increase of 0.6 million short tons by Knight Hawk Coal's Prairie Eagle mine offset those losses. An increase in coal production in 2009 of 0.4 million short tons by Mach Mining's Mach No. 1

mine, combined with the opening of Knight Hawk Coal's Prairie Eagle South mine and the restart of MaRyan Mining's Shay No. 1 mine (formerly Monterey Coal Company No. 1 mine), accounted for most of Illinois' increased production level.

Indiana produced a total of 36.6 million short tons in 2009, an increase of only 1.8 percent or 0.7 million short tons, but that was enough to vault it to the position of the largest coal-producing state in the Interior Region. Although there were large decreases in production at several mines, including a drop of 1.8 million short tons by United Minerals' Discovery mine and a drop of 0.6 million short tons at both Vigo Coal's Cypress Creek mine and Solar Sources' Craney mine, increases in production at four mines in Indiana as well as production at two new mines resulted in the increase in coal production for 2009. The four mines that had the higher production totals in 2009 were United Minerals' West 61 mine, higher by 1.3 million short tons; Sunrise Coal's Carlisle mine, higher by 0.7 million short tons; and both Peabody Energy's Francisco mine and Little Sandy Coal Company's Antioch mine, higher by 0.5 million short tons.

Texas coal is mainly lignite, the lowest rank of coal with the lowest amount of energy (or Btu), most of which is used in the electric power sector, primarily at mine-mouth facilities. The amount of Texas-produced lignite consumed by the electric power sector in the state in 2009 dropped by 16.2 percent, while the total amount of coal consumed in the electric power sector in Texas declined by only 6.3 percent. The discrepancy is due to the amount of subbituminous coal consumed for power production decreasing only slightly by 0.2 percent. Total coal production in Texas for 2009 was 35.1 million short tons, a decrease of 10.1 percent. Eight of the 12 mines in Texas had declines in coal production in 2009, with 3 of those mines accounting for the majority of the decrease. The three mines are Luminant Mining's Winfield South Strip and Tatum Strip, and Westmoreland Coal Company's Jewett mine, down by 2.1, 1.4, and 0.9 million short tons, respectively. On a positive note for Texas, Luminant Mining's Kosse mine began production in the second quarter of 2009, producing 0.9 million short tons.

The other states in the Interior Region (Arkansas, Kansas, Louisiana, Mississippi, Missouri, and Oklahoma), which together produced 8.7 million short tons of coal, accounted for a total of 5.9 percent of the entire region's production in 2009. Of these states, only Mississippi and Missouri had increases in their coal production from their prior-year levels.

Western Region

Although the Western Region is the largest coal-producing region in the United States, in 2009 coal production declined by 7.7 percent to a total of 584.5 million short tons and ended a five-year increasing production trend. The decrease of 49.1 million short tons resulted in a production level comparable to what was produced in 2005. Only two of the eight states in the Western Region (Alaska and North Dakota) had an increase in coal production for the year. Of all the coal-producing states in the Western Region, Alaska, with one mine, the Usibelli mine, has the smallest level of production. However, in 2009, it had the largest increase in production, 370 thousand short tons, or 25.0 percent, and ended the year with a total of 1.8 million short tons. North Dakota produced 29.9 million short tons of coal in 2009, an increase of 318 thousand short tons, or 1.1 percent. There are four mines in North Dakota, and in 2009 two of the mines – Falkirk Mining's Falkirk mine and Coteau Property's Freedom mine – had increased production levels that were more than enough to offset the declines experienced at the other two mines – Westmoreland Coal's Beulah mine and BNI Coal's Center mine.

Wyoming, the largest coal-producing state in the nation, a position it has held for two decades, continues to dominate the U.S. coal production picture. In 2009, coal production in Wyoming fell for the first time in 17 years. Total coal production in Wyoming in 2009 was 430.7 million short tons, a decrease of 37.0 million short tons, or 7.9 percent, but its share of U.S. total production still grew slightly. To show how Wyoming dominated the U.S. coal supply in 2009, it accounted for 73.7 percent of the Western Region production total, was 91.4 million short tons more than the entire Appalachian Region, was almost three times the Interior Region, and was more than 40 percent of the total U.S. coal production for the year. Although overall Wyoming coal production decreased in 2009, there were five mines that had at least some level of production increase.

The largest increase in coal production at any mine in Wyoming was achieved by Alpha Natural Resources' Eagle Butte mine, which produced 21.5 million short tons, an increase of 1.0 million short tons or 5.1 percent over the 2008 level. Peabody Energy's North Antelope Rochelle mine was again the largest coal mine in Wyoming and the U.S. in 2009, producing a total of 98.3 million short tons, an increase of 0.7 million short tons or 0.7 percent. This one mine produced more coal than any other state in the nation but two, West Virginia and Kentucky. The other three mines in Wyoming that had higher production in 2009 increased by a combined total of less than 203 thousand short tons.

During the second half of 2009, Arch Coal closed on its purchase of the Jacobs Ranch mine from Rio Tinto and subsumed it into the adjacent Black Thunder mine. If this had been counted as one mine for the entire year, it would have had the largest decline in coal production of any Wyoming mine, a drop of 20.6 million short tons. It also would have been the largest mine in the United States with a total of 110.1 million short tons, down from the 2008 level of 130.7 million short tons. Other Wyoming mines that had decreases in 2009 coal production of at least 1 million short tons were Peabody Energy's Caballo mine down 8.0 million short tons, Peabody Energy's Rawhide mine down 2.6 million short tons, Cloud Peak Energy's Antelope mine down 1.8 million short tons, and Arch Coal's Coal Creek mine down 1.7 million short tons.

In 2009, Montana produced a total of 39.5 million short tons, a decrease of 11.8 percent or 5.3 million short tons. Although there was an increase in production at Signal Peak Energy's Bull Mountain mine of 0.6 million short tons, the decreases in coal production at Western Energy's Rosebud mine of 2.7 million short tons and Decker Coal's Decker mine of 2.4 million short tons in 2009 accounted for the majority of the decline.

Colorado, the third largest coal-producing state in the Western Region, had a decrease in coal production for 2009 of 3.8 million short tons or 11.7 percent to end the year at 28.3 million short tons. Although 3 of the 11 mines in the state had increases in coal production in 2009, the decrease in Colorado's total production was accounted for primarily by 3 mines. Bowie Resources' Bowie No. 2 mine had a decrease of 1.6 million short tons, Arch Coal's West Elk mine had a decrease of 1.4 million short tons, and Colowyo Coal's Colowyo mine had a decrease of 1.3 million short tons.

Utah was the only other state in the Western Region to have a major decrease in coal production in 2009, declining by 10.9 percent to end the year at a total of 21.7 million short tons. Only one of the eight mines in the state had an increase in production in 2009 – Consol Energy's Emery mine, which had an increase of 0.2 million short tons. The majority of the decrease in coal

production in 2009 in Utah was the result of the declines at two mines – Canyon Fuel's Dugout Canyon mine and West Ridge Resources' West Ridge mine, which had decreases of 0.9 and 0.7 million short tons, respectively. Total coal production in Arizona and New Mexico declined in 2009 by 0.6 and 0.5 million short tons, respectively.

4.1.2.1 Coal Production by U.S. Coal Region

This section presents an overview of coal production activities and trends in the major U.S. coal-producing regions. Table 4-3 reviews these trends.

Table 4-3: Coal Production by U.S. Coal-Producing Region[36]

Region	2008 Mines	2008 Production	2007 Mines	2007 Production	Mine % Change	Production % Change
Appalachian Total	1,278	390,218	1,200	377,800	6.5	3.3
Underground	533	232,512	508	227,588	4.9	2.2
Surface	745	157,705	692	150,213	7.7	5
Northern	378	135,647	383	132,144	-1.3	2.7
Underground	86	105,234	88	106,023	-2.3	-0.7
Surface	292	30,413	295	26,121	-1	16.4
Central	841	233,959	768	226,329	9.5	3.4
Underground	439	114,997	412	110,103	6.6	4.4
Surface	402	118,962	356	116,227	12.9	2.4
Southern	59	20,611	49	19,327	20.4	6.6
Underground	8	12,281	8	11,462	-	7.1
Surface	51	8,330	41	7,865	24.4	5.9
Interior Total	99	146,586	100	146,668	-1	-0.1
Underground	30	65,117	34	62,519	-11.8	4.2
Surface	69	81,469	66	84,149	4.5	-3.2
Illinois Basin Total	72	98,875	71	95,660	1.4	3.4
Underground	28	64,609	31	61,924	-9.7	4.3
Surface	44	34,267	40	33,736	10	1.6
Western Total	58	633,597	58	621,012	-	2
Underground	20	59,450	21	61,683	-4.8	-3.6
Surface	38	574,147	37	559,329	2.7	2.6
Powder River Basin	17	495,964	17	479,496	-	3.4
Underground	-	-	-	-	-	-
Surface	17	495,964	17	479,496	-	3.4
Uinta Region	17	55,578	19	59,815	-10.5	-7.1
Underground	15	48,343	16	51,446	-6.3	-6
Surface	2	7,235	3	8,368	-33.3	-13.5
East of Mississippi River	1,351	491,935	1,272	477,006	6.2	3.1
West of Mississippi River	84	678,467	86	668,474	-2.3	1.5
U.S. Subtotal	1,435	1,170,401	1,358	1,145,480	5.7	2.2
Refuse Recovery	23	1,408	16	1,156	43.8	21.8
U.S. Total	1,458	1,171,809	1,374	1,146,635	6.1	2.2

Source: EIA, July 2010.

[36] Production in thousands of short tons.

Across the United States, the total number of mines increased by 6.1 percent and the amount of production grew by 2.2 percent from 2007 to 2008. With a few possible exceptions, both underground- and surfacing-mining production increased.

In 2008, the Western mines (much larger and fewer in number) continued to out-produce those in East, which tend to be greater in number and smaller in size. This trend is expected to continue according to EIA's long-term forecasts to 2035.

4.1.2.2 Selected Major Coal Company Profiles

This section compares the companies listed in Table 4-4. The information in Table 4-4 was obtained from a combination of sources, including Standards and Poors Research, Mergent Investment Research, and individual company websites and financial reports.

Table 4-4: Leading Coal Company Performance Comparison, Ranked by 2009 Total Revenues

Company Name	Revenues	Gross Margin	Net Income	EBITDA[1]	Total Assets	Total Liabilities	Employees
Peabody Energy Corp.	$6,012,400,000	25.69	$448,200,000	$1,326,900,000	$9,955,300,000	$6,205,600,000	7,300
CONSOL Energy, Inc.	4,621,875,000	36.29	539,717,000	1,261,151,000	7,725,401,000	5,939,853,000	8,012
TECO Energy, Inc.	3,310,500,000	30.15	213,900,000	768,000,000	7,219,500,000	5,134,100,000	4,073
Massey Energy Company	2,691,159,000	11.05	104,433,000	516,207,000	3,799,671,000	2,543,388,000	5,851
Arch Coal, Inc.	2,576,081,000	19.62	42,169,000	444,945,000	4,840,596,000	2,725,490,000	4,601
Alpha Natural Resources, Inc.	2,495,507,000	27.6	58,005,000	297,456,000	5,122,771,000	2,531,482,000	6,400
NACCO Industries, Inc.	2,310,600,000	17.66	31,100,000	71,700,000	1,488,700,000	1,092,100,000	8,200
Patriot Coal Corp.	2,045,283,000	-	127,243,000	283,567,000	3,618,163,000	2,682,669,000	3,500
Cloud Peak Energy, Inc.	1,398,200,000	33.24	381,701,000	394,187,000	1,677,596,000	1,424,691,000	1,529
Alliance Resource Partners, L.P.	1,231,031,000	31.5	192,157,000	223,553,000	1,051,400,000	731,537,000	3,090
International Coal Group	1,125,349,000	20.51	21,458,000	194,567,000	1,367,960,000	758,787,000	2,562
Walter Energy, Inc.	966,827,000	39.31	137,158,000	275,556,000	1,259,356,000	999,961,000	800
Allete, Inc.	759,100,000	-	61,000,000	181,200,000	2,393,100,000	1,463,600,000	1,411
James River Coal Co.	681,558,000	16.23	50,954,000	133,401,000	669,312,000	498,970,000	1,751
Headwaters, Inc.	666,676,000	21.98	(415,550,000)	(418,360,000)	891,924,000	587,493,000	2,740

Company Name	Revenues	Gross Margin	Net Income	EBITDA[1]	Total Assets	Total Liabilities	Employees
Penn Virginia GP Holdings LP	656,704,000	38.09	37,879,000	157,799,000	1,219,063,000	969,367,000	NA
Penn Virginia Resource Partners, L.P.	656,704,000	-	65,215,000	160,103,000	1,208,060,000	731,553,000	167
Westmoreland Coal Co.	443,368,000	15.86	(27,345,000)	20,725,000	772,728,000	912,710,000	1,109
Natural Resources Partners L.P.	256,084,000	-	114,080,000	210,564,000	1,523,590,000	758,364,000	NA
National Coal Corp.	88,035,482	6.12	(19,214,548)	(2,165,609)	52,813,528	65,116,437	273
U.S. China Mining Group, Inc.	64,998,456	58.16	25,086,827	34,000,560	89,986,287	10,800,081	71
America West Resources, Inc.	11,010,004	6.53	(8,704,926)	(1,649,189)	17,587,229	25,107,696	105

[1]Earnings before Interest, Taxes, Depreciation and Amortization

The data presented in Table 4-4 represent the total business interests and activities of the companies. In some cases, the companies are active in businesses other than coal.

Seven of the companies have total business revenues more than $2 billion: Peabody Energy, CONSOL Energy, TECO Energy, Massey Energy, Arch Coal, Alpha Natural Resources, and NACCO Industries. Each of these companies employs more than 4,000 people.

The top gross margin performers from this largest company group were CONSOL Energy, TECO Energy, Alpha Natural Resources, and Peabody Energy.

Some of the smaller companies in Table 4-4 performed even better in terms of gross margins: Walter Energy; Cloud Peak Coal; Alliance Resource Partners; and Penn Virginia Resource Partners, L.P.

4.2 BASELINE ECONOMIC SITUATION

4.2.1 Coal Consumption

Total coal consumption dropped by more than 11 percent during the 2005-2009 period, with the largest decline occurring in 2009, which was triggered by the economic recession that depressed demand by electric power generators and other markets, as shown in **Error! Reference source not found.**.

Table 4-5: U.S. Coal Consumption by Major Sector

Market	2005	2006	2007	2008	2009	2005-2009 % Change
Consumption by Sector						
Electric Power	1,037.50	1,026.60	1,045.10	1,040.60	936.5	-9.73

Coke Plants	23.4	23	22.7	22.1	15.3	-34.62
Other Industrial Plants	60.3	59.5	56.6	54.4	45.4	-24.71
Residential/Commercial Users	4.7	3.2	3.5	3.5	3.2	-31.91
Total	1,126.00	1,112.30	1,128.00	1,120.50	1,000.40	-11.15

Source: EIA. 2009. U.S. coal supply and demand review, 2009.

The most significant observation regarding the coal market is its continued dominance by electric power generation, which has historically accounted for 90 to 94 percent of total coal demand.

Preliminary data show that total coal consumption declined significantly in 2009, dropping by 10.7 percent from the 2008 level. Total U.S. coal consumption was 1,000.4 million short tons, a decrease of 120.1 million short tons, with all of the coal-consuming sectors having lower consumption for the year. Although all sectors had declines, the electric power sector (electric utilities and independent power producers), which consumes approximately 94 percent of all coal in the United States, is the overriding force for determining total domestic coal consumption.

In 2009, the recession's downward pressure on electricity production resulted in a large decrease in coal consumption for the sector. Coal consumption in the electric power sector decreased by 10.0 percent or 104.0 million short tons to end 2009 at 936.5 million short tons, while coal-based electricity generation in kilowatt hours (kW-h) decreased at a slightly higher rate of 11.1 percent, reflecting increasing volumes of lower-Btu Western coals (subbituminous and lignite) to generate electricity.

Nationally, total generation in the electric power sector declined in 2009 by 4.1 percent. The decline in total generation for the year was a direct result of the large loss in generation by coal and a slight loss in generation by the nuclear sector. Preliminary data show that nuclear power generation decreased in 2009 by 1.2 percent. The three other specified categories (natural gas, hydroelectric, and petroleum and other sources) had increases in their respective generation levels in 2009, with natural gas generation providing the largest increase in the number of kW-h. The increase in electricity generation by natural gas was a result of the large decline in natural gas prices. The average wellhead price of natural gas in 2009 was $3.71 per thousand cubic feet, a decrease of 53.4 percent from the 2008 average price of $7.96 per thousand cubic feet.

The economy and the weather (as measured by heating and cooling degree-days) are the two factors that drive total electricity demand in the United States. In 2009, the economy contracted as the U.S. GDP declined by 2.4 percent from 2008. The weather was also a factor in the decline of total electricity generation in 2009. The winter weather across a large portion of the country was somewhat warmer than it was in 2008, as well as warmer than the normal 30-year average. According to preliminary data from the National Oceanic and Atmospheric Administration, heating degree-days in 2009 were 1.0 percent lower than normal and 0.4 percent lower than 2008 for the country as a whole. Although the summer weather in 2009 was slightly warmer than normal, it was not as warm as it was in 2008. The summer weather in 2009 as measured in cooling degree-days was 0.2 percent higher than normal but 2.5 percent lower than the level experienced in 2008, which resulted in less need for electricity to run air conditioners and therefore lower demand for electricity.

Of the nine Census divisions, coal is a minor component (less than 20 percent) in the fuel mix for electricity generation in two divisions – New England and Pacific – and a major component (more than 50 percent) in five divisions – East North Central, West North Central, South Atlantic, East South Central, and Mountain. In the other two divisions, coal is one of two main fuel sources for the electric power sector. In the Middle Atlantic, coal competes with nuclear power for dominance, while in the West South Central, coal competes with natural gas.

In 2009, all nine Census divisions had a decline in total electricity generation, as well as a decline in coal-based generation, with a resulting large decrease in coal consumption for the electric power sector. Total coal consumption in the electric power sector fell by 104.0 million short tons in 2009, with two of the Census divisions – the South Atlantic and the East North Central – accounting for approximately one-half of the drop.

The South Atlantic Census Division typically accounts for approximately 20 percent of total U.S. electricity generation, while the East North Central Census Division typically accounts for approximately 16 percent of the total. Coal is the primary fuel for electricity generation in both divisions. In 2009, total generation in the South Atlantic Census Division decreased by 5.6 percent, while coal-based generation decreased by 17.7 percent. The decline in coal-based electricity generation in 2009 in the division resulted in a decrease in coal consumption of 30.8 million short tons, down 17.1 percent to end the year at 149.1 million short tons. As a consequence of the drop in coal consumption in the division, coal stocks at power plants increased in 2009 by 48.4 percent to end the year at 39.8 million short tons. This increase of 13.0 million short tons in the division accounted for almost one-half of the total increase in coal stocks in the electric power sector at the national level. Both natural gas and hydroelectric generation increased in the division in 2009.

While there was a large percentage increase in hydroelectric generation of 79.3 percent for the year, it still only accounted for slightly less than 2 percent of total generation for the division. Natural gas generation in the division increased in 2009 by 20.4 percent, as some power producers took advantage of the low natural gas prices to run generators, supplanting some of the need for coal-based generation. The share of natural gas generation in the division increased to 22.5 percent in 2009, up from the 2008 level of 17.7 percent, while the share of coal-based generation in the division dropped to 46.5 percent in 2009 from the 2008 level of 53.4 percent.

In 2009, total generation in the East North Central Census Division declined by 7.8 percent, while coal-based generation declined by 8.9 percent. While there were gains in natural gas, petroleum and other, and hydroelectric generation in the division of 5.0 percent, 16.9 percent, and 8.1 percent, respectively, these three sources are a small portion of total generation in the division, together accounting for less than 7 percent of the annual generation. Coal generally accounts for approximately 70 percent of generation in the division; this makes it the single largest coal-consuming Census division for the electric power sector, usually accounting for just under one-quarter of total U.S. coal consumption in the electric power sector. The decrease in coal-based generation in the division in 2009 resulted in a decrease in coal consumption of 20.9 million short tons, a decline of 8.8 percent.

In the East South Central Census Division, coal is the dominant fuel for generation. In 2009, total generation in the division decreased by 5.5 percent, while coal-based generation declined at a much higher rate of 19.0 percent. The petroleum and other category was the only other

category to show a decrease in generation in 2009 in the division. The decline in coal generation in the division resulted in a decrease of 18.5 million short tons of coal consumption, to a level of 95.6 million short tons, a drop of 16.2 percent from the 2008 level. Coal stocks held by power plants in the division increased in 2009 by 6.0 million short tons, to end the year at 20.9 million short tons. Generation by natural gas in the division increased its share in 2009 to 15.6 percent from the 11.5 percent it represented in 2008.

Total generation in the Middle Atlantic Census Division in 2009 decreased by 2.3 percent, with coal-based generation being the only category to show a decline for the year. The decrease in coal generation in the division was 15.3 percent, which resulted in coal's share of the division's generation to drop to 29.7 percent from the 34.3 percent it represented in 2008. Coal consumption in the electric power sector in the division in 2009 declined by 10.5 million short tons, or 15.7 percent. Natural gas generation was the category that had the largest percent increase in 2009 in the division, increasing by 12.0 percent, while hydroelectric generation increased by 7.0 percent, petroleum and other generation increased by 1.6 percent, and nuclear generation increased by 0.3 percent.

In the West South Central Census Division, coal competes with natural gas as the primary source for electric power generation, with each accounting for approximately 40 percent of the division's generation. Total generation in 2009 in the electric power sector in the division decreased by 1.3 percent, while coal-based generation declined at a higher rate of 5.3 percent and natural gas generation declined at a lower rate of 0.7 percent. Total coal consumption in 2009 for the electric power sector in the division decreased by 8.7 million short tons, or 5.6 percent, ending the year at a total of 147.1 million short tons.

More than one-half of the electricity generated in the Mountain Census Division is derived from coal. In 2009, total generation in the division declined by 3.3 percent, with coal-based generation declining by 6.1 percent. The two sources of increased generation in the division in 2009 were nuclear, increasing by 4.8 percent, and petroleum and other sources, increasing by 16.8 percent. Total coal consumption in the electric power sector in the division decreased in 2009, ending the year at 109.5 million short tons, a decline of 7.2 million short tons.

In the West North Central Census Division, coal is the dominant source for electric power generation, accounting for approximately three-fourths of the division's generation. Total generation in 2009 in the electric power sector in the division declined by 0.6 percent, the smallest decline of any of the nine Census divisions. Coal-based generation in the division decreased by 2.5 percent in 2009, with natural gas generation the only other category to have a decline in generation in the division. Total coal consumption in 2009 for the electric power sector in the division decreased by 4.0 million short tons, or 2.7 percent, ending the year at a total of 145.4 million short tons.

Total electric power sector generation in the New England Census Division declined in 2009 by 2.8 percent, while coal-based generation declined by 18.0 percent. However, coal accounts for less than one-sixth of total generation in the division, and in 2009 total coal consumption for electricity generation decreased by 1.7 million short tons, ending the year at a total of 6.7 million short tons.

Total generation in the Pacific Census Division in 2009 decreased by 3.3 percent, while coal-based generation decreased by 15.7 percent. Coal accounts for less than 5 percent of total generation in the division, and in 2009 total coal consumption for electricity generation declined by 14.9 percent to end the year at 8.9 million short tons.

Coal consumption in the non-electric power sector (comprising other industrial, coking coal, and the commercial and institutional sectors) declined for the fifth consecutive year in 2009. Coal consumption at coke plants decreased by 6.7 million short tons to end the year at 15.3 million short tons, a decline of 30.6 percent. The decline in U.S. coke production in 2009 was a result of the economic downturn in the year, when several steel plants idled production for extended periods in response to the worldwide drop in demand for their products.

In 2009, the manufacturing sector in the United States declined as a consequence of the recession, and as a result, coal consumption in the other industrial sector decreased by 9.0 million short tons to end the year at 45.4 million short tons, a drop of 16.6 percent. Within the manufacturing sector of the NAICS, all of the manufacturing subsectors showed lower coal consumption for 2009.

All of the five major coal-consuming manufacturing subsectors had large decreases in coal consumption for 2009. The declines ranged from 0.7 million short tons in the food-manufacturing segment to 3.7 million short tons in the nonmetallic mineral products segment. Also contributing to the overall decline in consumption for the other industrial sector were decreases of 1.2 million short tons by the primary metal-manufacturing segment, 1.4 million short tons for the chemical-manufacturing segment, and 1.5 million short tons for the paper-manufacturing segment. Coal consumption in the commercial and institutional sector decreased somewhat in 2009, ending the year at 3.2 million short tons.

Coal trade is a significant part of the industry's economics. A review of trade trends is provided in **Error! Reference source not found.**. U.S. economic conditions and exchange rates are major factors in coal trade.

Table 4-6: Coal Trade Trends, 2005-2009

Area	2005	2006	2007	2008	2009	2005-2009 % Change
U.S. Coal Trade						
Exports	49.9	49.6	59.2	81.5	59.1	18.44
Steam Coal	21.3	22.1	27	39	21.8	2.35
Metallurgical Coal	28.7	27.5	32.2	42.5	37.3	29.97
Imports	30.5	36.2	36.3	34.2	22.6	-25.90
Steam Coal	28.7	34.6	34.7	32.5	21.6	-24.74
Metallurgical Coal	1.8	1.7	1.7	1.7	1	-44.44
Net Exports	19.5	13.4	22.8	47.3	36.5	87.18

Source: EIA. 2009. U.S. coal supply and demand review, 2009.

Total coal exports grew by more than 18 percent during the 2005-2009 period, metallurgical coal seeing the biggest rise (almost a 30 percent jump). Conversely, imports saw a decline of 26 percent during the same period.

EIA estimates that coal consumption in the electric power sector grew by nearly 5 percent in 2010, primarily the result of higher electricity consumption because of the very warm summer. EIA projects that coal consumption in the electric power sector will decrease by 0.7 percent in 2011, as increases in generation from natural gas, nuclear, and wind back out coal. In 2012, projected electricity generation increases by 2.5 percent and coal consumption in the electric power sector grows by 3.4 percent.

4.2.2 Coal Price Trends

Error! Reference source not found. A trend in all sectors is the increase in prices over the five-year period (2005-2009). Although it was a "down" year for coal production and consumption in 2009, domestic coal prices continued to increase, rising for the sixth consecutive year. The primary reason that domestic coal prices continued to climb was that a number of coal contracts were signed in 2008 during the dramatic rise of spot coal prices that affected the contract prices. The majority of coal sold in the electric power sector is through long-term contracts (covering a period of one year or longer), in conjunction with spot purchases to supplement the demand. As contracts expire and are renegotiated, the prevailing spot price influences the contract price.

According to preliminary data for 2009, coal prices at electric utilities (a subset of the electric power sector) increased for a ninth consecutive year, to $44.72 per short ton, an increase of 8.2 percent over the 2008 price. Coal prices at independent power producers for 2009 increased to $39.72 per short ton, an increase of 1.9 percent. The average delivered price of coal to the other industrial sector increased by 2.3 percent to an average price of $64.87 per short ton in 2009. In 2009, the delivered price of coal to U.S. coke plants increased by 21.1 percent to reach an average price of $143.04 per short ton. The average delivered price of coal to the commercial and institutional sector increased in 2009 by 12.5 percent to $97.28 per short ton.

Table 4-7: Coal Price Trends Across Industry Sectors

Sector	2005	2006	2007	2008	2009	2005-2009 % Change
Domestic						
Average Delivered Price						
Electric Utilities	$31.22	$34.26	$36.06	$41.32	$44.72	43.24
Independent Power Producers	$30.39	$33.04	$33.11	$38.98	$39.72	30.70
Coke Plants	$83.79	$92.87	$94.97	$118.09	$143.04	70.71
Other Industrial Plants	$47.63	$51.67	$54.42	$63.44	$64.87	36.20
Commercial/Institutional	-	-	-	$86.50	$97.28	
International						
Average Free Alongside Ship (f.a.s.) Price						
Exports	$67.10	$70.93	$70.25	$97.68	$101.44	51.18
Steam Coal	$47.64	$46.25	$47.90	$57.35	$73.63	54.55
Metallurgical Coal	$81.56	$90.81	$88.99	$134.62	$117.73	44.35
Average Customs Import Value (c.i.v.) Price						
Imports	$46.71	$49.10	$47.64	$59.83	$63.91	36.82
Steam Coal	$43.35	$46.15	$45.31	$56.75	$61.40	41.64
Metallurgical Coal	$101.88	$109.36	$96.05	$117.18	$115.93	13.79

Source: EIA.

4.2.3 U.S. Coal-Mining Industry Demographics

The data in **Error! Reference source not found.** provide insights into the number of firms, establishments, small businesses, startups, and business failures in the U.S. coal industry. Each of the terms used is defined at the beginning of this section.

Table 4-8: U.S. Coal-Mining Industry Demographics

Industry Demographic	2007	2008	2009	2007-2009 Percent Changes
Firms:	1,647	1,464	1,428	-13.30
Establishments:	2,024	1,803	1,756	-13.24
Small Businesses:	761	775	753	-1.05
Startups:	15	12	1	-93.33
Branches:	377	339	328	-13.00
Failure Rates				
	2007 Firms	**2009 Survivors**		**Failure Rates**
Firms:	1,647	1,200		27.14%
Establishments:	2,024	1,509		25.44%
Small Businesses:	761	638		16.16%
Startups:	15	10		33.33%
Branches:	377	307		18.57%

Source: BizMiner.com. 2010. Accessed September 9, 2010. [37]

Error! Reference source not found. indicates the following:

- The number of active firms in the coal-mining industry has declined by more than 13 percent since 2007, reflecting the growing consolidation in the industry, which is expected by experts to continue. This trend is also influenced by the shift to Western states, which is dominated by a few large coal operators.
- Similarly, operating business establishments have declined by more than 13 percent.
- The number of small businesses in the industry has been reduced by approximately 1 percent. "Small business" is defined as a single-site firm with fewer than 25 employees.
- Startup activity has been negligible, which reflects the industry's maturity and capital intensity.

[37] BizMiner (the Brandow Company, Inc.) is a leading online provider of industry financial analysis and market research, with thousands of customers and subscribers among valuation professionals, Certified Public Accountants, consultants, institutions of higher learning, financial institutions, real estate and market research professionals, and small business owners. BizMiner has built its reputation on quality, granular industry research and data development, which reports on more than 16,000 lines of business in national and local markets. BizMiner's dedication to hard-to-find, quality product has been recognized by professional associations, the Internal Revenue Service, and *Business Week*, among others.

4.2.4 Key Competition Drivers

The demand for coal comes mainly from electric power generators, accounting for nearly 94 percent of total consumption. This gives electric power companies considerable leverage with coal producers. Many electric power companies, such as Tampa Electric in Florida, own and operate their own coal mines, increasing their leverage in the coal market even more.

Business profitability depends on efficient operations, because coal is a commodity sold on the basis of price. Larger companies, such as those listed above, have significant economies of scale in production and distribution. Larger producers have moved to larger loading equipment and trucks to achieve greater productivity. Smaller companies can compete in the industry if they hold long-term contracts, or if they supply local customers. The industry is capital-intensive, with average annual revenue per employee of approximately $300,000.

4.2.5 Coal-mining Products and Operations

Coal comes in many grades of heat value and with various types of impurities, such as sulfur. Low-grade coals, such as peat and lignite, have a low heat value, a high moisture content, and high residual ash when burned. Anthracite is the highest-grade coal, with a 95 percent carbon content, but is found in only a few areas in the United States. Bituminous coal is the most plentiful, with a moisture content less than 20 percent, and heat values that range from 8,000 to 14,000 Btu per pound.

Coal usually contains contaminating materials, the most important of which are sulfur and metals. When coal is burned, contaminants can be either in the air (sulfur and Hg) or in the ash (heavy metals), unless they are controlled through pollution abatement technology.

Coal is produced from either underground mines or surface mines. Approximately 1,500 mines operate in the United States.[38] In underground mines, coal is removed using either room-and-pillar or longwall mining techniques. Surface mines use shovels, loaders, and trucks, and in some cases draglines, to remove the earth and rock (the "overburden") that covers a coal seam, after which large excavators, shovels, and loaders remove the coal. Many mining operations include preparation plants, where the coal is crushed to the proper size for customers so that the delivered coal product can be used directly.

Operators sometimes own the land they mine, but most often hold leases that allow them to remove the coal in exchange for royalty payments. Some operators mine coal under contract to the owners. Ultimately, the value of a mine depends upon its profitability.

Because coal is bulky and costly to ship, transportation from mine to customer is an important consideration, because customers usually pay those costs. Because it is less expensive to move electricity than coal, utility companies, the primary coal customer, locate some generation facilities close to mining areas. Approximately 50 percent of coal is moved by rail, while barges, trucks, slurry pipelines, and conveyor belts move the remainder. For unit train loading, coal that will be shipped by rail is fed into giant silos, which can precisely load a constantly moving train of 100 hopper cars in less than an hour.[39]

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[38] EIA. Table 1: coal production and number of mines by state and mine type.

[39] EIA. 2010. Coal transportation database, 2010.

4.2.6 Coal Industry Market Considerations

As mentioned previously, companies that generate electricity are the primary customers of the U.S. coal industry, accounting for more than 94 percent of U.S. coal consumption. Coal companies also sell coal to industrial customers to produce steam for various manufacturing processes and to the steel industry to make coke for steel making. Such metallurgical coal has tighter grade specifications than ordinary steam coal.

Because approximately one-half of all electricity generated in the United States is produced using coal, coal producers are greatly concerned regarding the issues facing the electricity industry, including air pollution and the disposal of coal combustion wastes (fly ash, bottom ash, and scrubber sludge).

Most coal is sold directly to end-users through long-term supply contracts, and the remainder is sold either in the spot market or through brokers. The terms of long-term contracts vary significantly among customers, and usually include provisions for price adjustments, coal quality and quantity, and a variety of renegotiation and termination conditions. Mining operators depend highly on their customers; many sell to just a few large customers, and small operations may sell to just one.

Coal prices are determined largely by the grade of the coal, including its sulfur content and heat value. Although prices are usually quoted free on board at the mine, the delivered price to their generation facilities is of greatest concern to electric utility customers. Prices are often quoted in dollars per Million British Thermal Unit (MMBtu) because the heat content of coal varies from mine to mine, and even within the same mine. Prices are also quoted in dollars per ton.

As with most businesses, both mine operators and power producers seek to maximize the difference between the price they charge and the costs they pay. One method of increasing profits is to increase efficiency. For mine operators, this might mean increasing the number of tons of coal produced per miner per hour. For power producers, this might mean increasing the number of kilowatts produced per unit of coal burned. Statistics show that in the United States, for example, both mine operators and power producers have become increasingly efficient.

However, there are other ways to increase profits without raising prices. Cost shifting, the transfer of costs (however interpreted) onto other, often unwilling, individuals or institutions, is just as effective at increasing profits as increasing efficiencies.

Many mine operators' costs of conducting business have historically been borne by miners, a pattern that continues in some cases. Shifted costs may appear in the form of unnecessary occupational hazards, such as poorly ventilated mines, inadequate safety training, and inadequate safety equipment. Any additional profits that result from these shifts are enjoyed by the investors. Similarly, communities situated near coal mines may bear the consequences of cost shifting in the form of serious water pollution problems resulting from decisions by mine operators to forgo environmentally sound but more expensive mining practices. These types of cost-shifting behaviors may enable mine operators to keep the price of coal low, thereby enabling them to maintain or increase profits without increasing the price of their product.

Another example of cost shifting involves power plant emissions, especially CO_2emissions. Currently, power producers that depend on coal (as well as all other users of fossil fuels) emit all

of the CO_2they produce directly into the atmosphere. This distributes the cost of coal consumption among everyone in the world because everyone pays costs associated with climate change. However, power producers keep all of the profits generated by power production. Costs are shared; profits are not. If those power producers with significant CO_2emissions were to pay the costs associated with the emissions, coal-fired power plants would be much less attractive investments relative to the available alternatives. Similar statements can be made of other types of power plant emissions.

4.2.7 Coal Industry Financial Considerations

Error! Reference source not found. Provides an overall indication of the coal industry's profitability during the 2007-2009 period.

Table 4-9: Coal-Mining Industry Profitability Measures

Profitability Measure	2007	2008	2009
EBITDA: Business Revenue (%)	7.02	10.38	7.47
Pre-tax Return on Assets (%)	3.73	-0.54	-4.42
Pre-tax Return on Net Worth (%)	10.35	-1.62	-100.13
Pre-tax Return on Business Revenue (%)	5.63	-0.79	-8.05
After-tax Return on Assets (%)	2.47	-0.45	-4.42
After-tax Return on Net Worth (%)	6.84	-1.37	-100.13
After-tax Return on Business Revenue (%)	3.72	-0.67	-8.05

Source: BizMiner.com (579 coal-mining firms included in this analysis).

Compared to two years ago, all measures of profitability are down, which is consistent with many other industries pressed by the economic downturn since the end of 2007. As the cost impacts of the proposed SPR are considered, the financial health of the coal-mining industry should be considered.

4.2.8 Regulatory Considerations

Coal-mining companies face a large number of state and federal regulations, directly through their operations and indirectly through their major customer: the electric utility industry.

Regulatory compliance has significant influence on coal-mining company financial conditions, as reflected in the interviews conducted for this study.[40] Direct regulations concern permits to operate; safety of operations, under the Federal Mine Safety and Health Act; dust pollution; land reclamation after mining, under the SMCRA; assurance of pension benefits for miners; and medical expenses for miners with "black lung" disease, under the Black Lung Benefits Reform Act. Major indirect regulations concern air pollution, fly ash disposal, and deregulation of the electric utility industry. The large number of regulations applicable to coal operations requires significant attention from managers.

Of considerable regulatory concern are the provisions of the Clean Air Act (CAA) that tighten allowable emissions of sulfur dioxide, the main cause of acid rain, from electric generation plants. Tighter restrictions are also required for emissions of nitrogen oxide, a key component of

[40] These include interviews with NMA, various state mining regulators and associations, and coal companies such as TECO Coal and International Coal.

smog, and for Hg. Utilities can reduce these emissions by burning cleaner coal, investing in pollution control devices, or burning fuels such as natural gas. Burning natural gas also eliminates the disposal problems of fly ash, which sometimes contains toxic metals. Historically, to comply with the CAA, utilities bought more compliance coal, which emits less than 1.2 pounds of sulfur dioxide per MMBtu when burned. Now that FGD systems are in place, utilities can burn high-sulfur coal.

To ensure that mines, especially surface mines, are returned to an acceptable state of nature (reclamation), coal operators must post bonds for current operations and pay into a fund to remediate abandoned mines under the AML Fund. The AML Fund fee is used to pay for pre-SMCRA (or pre-1977) liabilities. Some unionized operators must pay into a retirement fund established by the Coal Industry Retiree Health Benefit Act.

4.2.9 Human Resource Considerations

As mentioned in numerous reports and histories of the coal mining industry, employment in coal mining tends toward a "boom-and-bust" cycle triggered by changes in coal prices and, more recently, by regulatory changes that have adhered to stricter environmental standards associated with coal production and end use of the product. Black, McKinnish, and Sanders (2004) performed an economic analysis of the boom-and-bust cycle in the Appalachian region from the 1970s to 1980s. They found that, during that period, increased coal production contributed approximately 2 additional jobs for every 10 jobs created in the coal industry in the counties analyzed. Conversely, the loss of 10 jobs during a decline in the coal industry caused the loss of approximately 3.5 jobs in the counties analyzed. They also found that poverty rates were substantially affected during the up- and downswings of the industry, indicating that the poor benefited from the expansion of the coal industry during this period.

Analysis of historical employee productivity from the period referenced in Black, McKinnish, and Sanders (2004), when compared to 2009 average employee productivity by method (i.e., underground or surface), indicates that during the peak period from 1978 to 1982, the national average underground mining productivity was 1.21 short tons per employee hour and 3.22 short tons per employee hour for surface coal mining, while in 2009 the productivity for underground mining averaged 3.01 short tons per employee hour and surface mining averaged 9.15 short tons per employee hour (EIA, 2010c). The EIA (2006) indicates that the average number of mining employees in 1973 was 152,204, and that number increased to 175,642 by 1983 just after the end of the peak period (Black, McKinnish, and Sanders, 2004). More recent employment data indicate that in 2009, the coal industry employed 87,755 (EIA, 2010b). Comparatively, coal production in 1973 was over 602.5 million tons; in 1983, 783.1 million tons; and in 2009, 1,072.8 million tons (EIA, 2010c). Technological advances increased production while generally decreasing employment in the industry, as fewer employees are required for production (Bell and York, 2010).

The NMA provides information on the total number of direct employment positions supported by coal mining throughout the United States. Employment numbers in the 2010 NMA report were derived from 2008 employment figures from the MSHA, whereas data for the analysis of the alternatives were derived from the EIA Annual Coal Report and the BLS industry data at the lowest level possible for the geographic areas analyzed. The NMA indicates that total mine workers in 2008 consisted of 85,040 positions, with an additional 7,570 in support positions, and

61,410 employment positions related to coal transportation activities. The number of mine workers was similar to the EIA employment data for 2008, indicating 86,859 mine employees. Variations in methodology account for differences in employment numbers. The MSHA data includes contractors that work on mine sites, in addition to mine employees. The analysis does not account for the transportation-related workforce as direct employment positions (i.e., employees working directly for coal mining); transportation-related jobs were included in the indirect and induced workforce.

In addition to the NMA report, states also provide estimates of the economic contributions of the coal mining industry to the state economies in terms of employment positions, tax revenues, and economic output.

In 2009, U.S. coal production exceeded 1.0 billion short tons from over 1,400 mines in 27 states. This coal was produced by over 87,000 employees, which was a 1% increase in total employment in coal mining from 2008 (EIA, 2010a, b). On average, 5.6 short tons of coal were produced per employee per hour, which was a decline of less than 6.0%. In 2009, over 140 million persons were employed in the United States, indicating that coal mining accounts for 0.06% of total U.S. employment. In the combined coal mining regions, over 64 million persons were employed in 2009, indicating that coal mining accounted for 0.1% of total employment in the study area. Coal mining industry employment represents a minor portion of the total U.S. employment; however, the coal mining industry is a significant employer in certain local areas.

4.2.9.1 Employment Changes in Coal Mining

While the coal mining industry recorded a 1.5% average annual employment growth rate during the last decade, employment fluctuated substantially from year to year. For example, coal mining employment declined 5.9% between 2002 and 2003, increased 4.7% between 2004 and 2005, increased 5.5% between 2005 and 2006, and increased 5.2% between 2007 and 2008 (BLS, 2010a). The coal mining industry recorded a 13.9% increase in employment between 2000 and 2009, an increase of approximately 10,000 workers (BLS, 2010b). Table 4-10 lists the estimated number of employment positions generated by the estimated production, by mining type.

Table 4-10: Direct Coal Mine Employment[1] Positions Estimated by Production Type by Region

Coal-Producing Region	Estimated Number of Direct Coal Mine Employment Positions[2]		
	Underground	**Surface**	**Total**
Appalachian Basin	38,612	22,769	61,381
Colorado Plateau	4,818	2,055	6,873
Gulf Coast	2,851	5,001	7,851
Illinois Basin	7,546	2,792	10,338
Northern Rocky Mountain/Great Plains	338	9,581	9,920
Northwest	0	94	94
Other Western Interior	60	325	385

[1] - Includes all employees engaged in production, preparation, processing, development, maintenance, repair shop, or yard work at mining operations, including office workers, per EIA 2010 Annual Coal definition of coal mine employment.

[2] – All estimated employment positions are based on average productivity per employee by extraction type and the estimated production under this alternative, as previously described.

Source: Calculations derived from EIA 2010a, 2010b

4.2.9.2 Estimated Employment Changes in Remainder of Economy

When compared with employees of all industries nationwide, coal mining was a growing industry, on average, during the decade. Between 2000 and 2009, the total number of private employees had an average yearly decline of 0.2%, with the largest decline (5.2%) between 2008 and 2009, while employment in the coal mining industry increased by 1.2% between 2008 and 2009 (BLS, 2010a, b).

Various coal mining states and coal-related industry associations have determined the overall impact of the coal mining industry to the state economies. The state of Illinois (Illinois Department of Commerce and Economic Opportunity, Office of Coal Development, 2008) found that every coal mining job contributed six additional jobs in rural Illinois. Other states (Kentucky, New Mexico, Pennsylvania, Utah, and Wyoming) found that coal mining generated additional employment in a range between two to just under four positions (Kentucky Office of Energy Policy, Division of Fossil Fuels & Utility Services and the Kentucky Coal Association, 2008; Peach, 2010; Allegheny Conference on Community Development, 2010; Perlich, Hogue, and Downen, 2010; and Wyoming Mining Association, 2010). The NMA (2010) indicated that nationally, coal mining generated an additional 401,250 indirect and induced employment positions from 154,020 direct employment positions in the industry, equating to approximately 2.6 additional employment positions for every 1 direct position in the coal mining industry.

As detailed in the Appendix I of the Draft RIA, the coal mining industry has a varied–magnitude impact on employment in ancillary industries and throughout the remainder of the economy based on the state. For example, in the Appalachian states, every employment position created in the coal mining industry could generate up to 2.13 additional positions in Virginia or as few as 1.07 positions in West Virginia. In the interior states, each new coal mining employment position in Missouri could generate 2.29 positions in Missouri or 1.14 positions in Arkansas. In the Western states, each new coal mining position could produce 1.91 positions in Colorado or as few as 0.98 positions in Wyoming. On average, 1.46 employment positions are generated in the Appalachian states, 1.73 positions are generated in the interior states, and 1.40 positions are generated in the Western states by the coal mining industry.

4.2.9.3 Earnings and Personal Income

4.2.9.3.1 Earnings and Personal Income Changes from Coal Mining

The Bureau of Economic Analysis (BEA) indicated that the mining industry (except oil and gas) generated more than $19.5 billion in personal earnings in 2008, which was a 42.9% increase from the personal earnings received in 2001 (BEA, 2010a). Table 4-11 lists the total estimated personal earnings and total coal mining personal earnings compared to the overall total personal earnings derived from each region. Overall, coal mining earnings contribute a small percentage to total regional personal earnings, though the earnings may be locally substantial. Overall, in the Gulf Region and the Northwest, personal earnings from coal mining employment contribute almost twice as much to the regional earnings when compared to all other regions.

Table 4-11: Estimated Personal Earnings from Estimated Direct Coal Mine Employment by Production Type by Region

Coal-Producing Regions	Estimated Personal Earnings ($1,000)			Total Personal Earnings ($1,000)	Coal Personal Earnings as a Percentage of Total Personal Earnings
	Underground	Surface	Total		
Appalachian Basin	1,966,201	1,122,251	3,088,452	318,821,701	1.0
Colorado Plateau	229,366	98,871	328,237	17,232,940	1.9
Gulf Coast	153,623	249,744	403,367	10,838,632	3.7
Illinois Basin	421,017	154,653	575,670	40,674,605	1.4
Northern Rocky Mountain/Great Plains	18,385	453,109	471,494	29,161,383	1.6
Northwest	0	5,223	5,223	178,139	2.9
Other Western Interior	3,678	12,864	16,542	11,757,863	0.1

Source: Calculations derived from BLS, 2009; EIA, 2010a, 2010b.

4.2.9.3.2 Estimated Earnings and Personal Income Effects in Remainder of Economy

The coal mining industry generates indirect and induced employee compensation in other industries, Table 4-12 lists the estimated multipliers by state divided by region as adapted from the state baseline information provided in the Draft RIA (Appendix I). The coal mining industry also generates indirect and induced economic output throughout the economy in direct relation to the value of its economic output.

Table 4-12: Estimated Statewide Multipliers for Economic Output, Employment, and Compensation Generated from Existing Coal Mining Activities

State	Estimated Statewide Multiplier		
	Economic Output	Employment	Compensation
Appalachian Basin			
Alabama	0.48	1.77	0.71
Kentucky	0.52	1.28	0.60
Maryland	0.54	1.15	0.80
Ohio	0.63	1.51	0.80
Pennsylvania	0.73	1.79	1.08
Tennessee	0.62	1.01	0.90
Virginia	0.56	2.13	1.17
West Virginia	0.39	1.07	0.40
Regional Values	*0.52*	*1.40*	*0.66*
Colorado Plateau			
Arizona	0.59	1.68	0.72
Colorado	0.61	1.91	0.91
New Mexico	0.38	1.12	0.42
Utah	0.60	1.58	0.73
Regional Values	*0.57*	*1.63*	*0.74*
Gulf Coast			

State	Estimated Statewide Multiplier		
	Economic Output	Employment	Compensation
Louisiana	0.51	2.10	0.64
Mississippi	0.40	1.45	0.75
Texas	0.66	1.97	1.02
Regional Values	*0.64*	*1.96*	*0.99*
Illinois Basin			
Illinois	0.72	1.53	0.87
Indiana	0.45	1.95	0.80
Kentucky	0.52	1.28	0.60
Regional Values	*0.53*	*1.40*	*0.56*
Northern Rocky Mountains and Great Plains			
Colorado	0.61	1.91	0.91
Montana	0.46	1.28	0.48
North Dakota	0.37	1.19	0.42
Wyoming	0.32	0.98	0.37
Regional Values	*0.41*	*1.24*	*0.50*
Northwest			
Alaska	0.47	1.21	0.48
Other Western Interior			
Arkansas	0.41	1.14	0.51
Kansas	0.44	1.58	0.81
Missouri	0.55	2.29	0.68
Oklahoma	0.48	1.54	0.72
Regional Values	*0.52*	*1.97*	*0.69*

Source: Calculations derived from Appendix I, OSM RIA, 18 October 2010

4.2.9.4 Poverty Levels

Within in each coal-producing region, Mississippi (81.7%), New Mexico (63.6%), Arkansas (58.7%), Alabama (56.7%), Kentucky (55.8%), and Louisiana have greater than 50% of the counties with 2009 poverty rates exceeding 19%. Table 4-13 presents the calculated poverty rates for the combined counties in each coal-producing region. Overall, the Northwest and the Appalachian Basin contain the highest percentage of counties considered to be concentrated poverty areas (greater than 20% of the population falls below the poverty threshold), as defined by the USCB. The Northwest and Colorado Plateau had the greatest percentage of the population below the poverty threshold at the individual level, indicating regions that could be considered concentrated poverty areas. The counties that make up the coal-producing region in the Northwest, the Colorado Plateau, and the Gulf Region have the highest childhood poverty rates.

Table 4-13: Poverty Rates in the Combined Counties by Region, 2000 and 2009

Coal-Producing Region	2000			2009			Percentage Point Change from 2000 to 2009		
	Percent of Total Counties - Poverty Areas	Individual Poverty Rate	Childhood Poverty Rate	Percent of Total Counties - Poverty Areas	Individual Poverty Rate	Childhood Poverty Rate	Percent of Total Counties - Poverty Areas	Individual Poverty Rate	Childhood Poverty Rate
Appalachian Basin	38.6%	13.7%	16.4%	46.5%	16.2%	23.1%	7.9%	2.5%	6.7%
Colorado Plateau	11.1%	20.1%	25.3%	33.3%	18.3%	25.2%	22.2%	-1.8%	-0.1%
Gulf Coast	15.8%	17.1%	23.4%	21.1%	17.1%	25.2%	5.3%	0.0%	1.9%
Illinois Basin	7.4%	12.4%	16.6%	25.9%	16.4%	23.3%	18.5%	4.1%	6.8%
Northern Rocky Mountains and Great Plains	18.8%	10.2%	13.3%	12.5%	12.6%	17.8%	-6.3%	2.4%	4.5%
Northwest	100.0%	23.7%	27.8%	100.0%	22.7%	28.3%	0.0%	-1.0%	0.5%
Other Western Interior	23.1%	13.8%	18.6%	30.8%	16.3%	23.2%	7.7%	2.5%	4.6%

Source: Calculations derived from USCB, 2002, 2010b.

All coal-producing counties in Alaska (1 county), Arizona (1 county), Louisiana (2 counties), Mississippi (1 county), and New Mexico (2 counties) had greater than 19.0% of the population below the poverty threshold in 2009. Kentucky had 24 of 29 counties with a poverty rate exceeding 19.0% (82.8% of total coal-producing counties). Overall, the coal-producing counties in Kentucky accounted for 36.3% of the total counties in the state with a poverty rate above 19.0%. Based on the 2009 poverty data, Kentucky had 67 counties (55.8% of all counties) with a poverty rate exceeding 19.0% and 72 counties (60.0% of all counties) with a poverty rate equal to or greater than 18.4%, which is the statewide poverty rate. In West Virginia, 15 of the 26 coal-producing counties (57.7%) had a poverty rate greater than 19.0%. Of the total counties in the state that were at or above a 19.0% poverty rate, coal-producing counties accounted for 55.6%. Overall, the coal-producing counties in all states constitute only a small to moderate percentage (less than 15%) of the total number of counties in each state that have a poverty rate at or above 19.0%.

4.2.9.5 Income and Severance Taxes

The primary sources of tax revenues expected to be affected by changes in coal mining activity are state income taxes associated with coal mining employment, state severance taxes levied on active coal mines, and coal industry contributions to the AML fund, which are dispersed to the states. Other state and local tax revenue sources, such as corporate income taxes and property taxes, may be affected by coal industry changes in certain locations; however, impacts on these tax revenue sources are not as directly attributable to coal mining industry changes. In addition, for coal deposits located on and extracted from federal lands and federal lands held in trust for tribes, these revenue resources distributed back to states assist in funding regional and local priorities significant for citizens' quality of life.

The AML fund receives substantially different levels of contributions from the seven coal-producing regions. As shown in Table 4-14 the AML contributions are derived from surface

mining at a much higher rate than from underground mining. The greatest contributor by far is the Northern Rocky Mountains and Great Plains region, where the estimated AML fund contributions from surface mining activities alone exceed the combined total contributions from all other regions.

Table 4-14: Estimated AML Fund Contributions by Region

Coal-Producing Regions	Estimated AML Fund Contributions ($1,000)		
	Underground	Surface	Total
Appalachian Basin	29,731	47,053	76,785
Colorado Plateau	7,530	10,799	18,330
Gulf Coast	1,658	17,041	18,699
Illinois Basin	8,722	10,794	19,516
Northern Rocky Mountain/Great Plains	495	169,592	170,087
Northwest	0	465	465
Other Western Interior	60	472	532

Source: Calculations derived from DOI, 2008, EIA, 2010a.

An analysis of the distribution of AML funds back to coal-producing states (Table 4-15) shows that, in 2009 and 2010, OSM distributed more than $328.9 million to coal-producing states. In addition, OSM distributed more than $61.5 million in administration and enforcement grants.

Table 4-15: 2009 AML Fund Distribution to States

State	Coal Production (1,000 short tons)	AML Funds Distribution ($)	Administration and Enforcement Grants ($)
Alabama	18,796	5,871,464	1,313,950
Alaska	1,860	2,389,351	224,254
Arizona[1]	7,474		
Arkansas	5	2,322,179	156,703
Colorado	28,267	7,383,764	2,301,561
Illinois	33,748	12,356,792	2,895,394
Indiana	35,655	13,358,446	1,964,389
Kansas[1]	185	2,720,188	111,699
Kentucky[1]	107,338	31,184,323	10,960,193
Louisiana	3,657	334,774	168,095
Maryland	2,305	2,630,409	713,664
Mississippi	3,440	242,357	159,863
Missouri	452	1,857,121	234,318
Montana	39,486	10,705,147	1,440,101
New Mexico[1]	25,124	5,668,717	865,000
North Dakota	29,945	3,498,697	798,743
Ohio	27,501	8,675,639	2,969,654

State	Coal Production (1,000 short tons)	AML Funds Distribution ($)	Administration and Enforcement Grants ($)
Oklahoma	956	3,592,207	1,082,511
Pennsylvania	57,979	43,807,638	11,469,117
Tennessee[1]	1,996	1,896,843	
Texas	35,093	4,147,548	1,977,402
Utah	21,718	3,970,533	2,037,196
Virginia	21,175	9,257,897	3,911,857
West Virginia	136,971	52,204,675	11,711,912
Wyoming	431,107	98,845,000	2,289,321

Sources: 2010 Annual Evaluation Reports by States and Tribes, OSM.
[1]2009 Annual Evaluation Reports by States and Tribes, OSM, due to lack of available 2010 data.

Further analysis of the need for AML funds becomes apparent when reclamation costs, both funded and unfunded, are reviewed (Table 4-16). Throughout the United States, all AMLs have created more than $12.6 billion in costs for reclamation. Approximately $3.0 billion in reclamation projects have been completed; however, as of December 2010, only $344.8 million of additional reclamation projects had been funded. This leaves approximately $9.3 billion in unfunded reclamation projects. These ongoing costs to states and ongoing infrastructure maintenance have led to fiscal analysis reports on the impact of the coal mining industry on state budgets. In the *Impact of Coal on the Kentucky State Budget*, Konty and Bailey (2009) indicate that the net impact of the coal mining industry on the state budget is essentially a subsidy to the coal industry of almost $115 million. In West Virginia, Boettner and McIlmoil (2010) concluded that the net impact was a cost to the state budget exceeding $42 million. The Boettner and McIlmoil estimate was recalculated from McIlmoil et al. (2010) and Kent and Sowards (2010).

Table 4-16: AMLs Reclamation Costs, All Surface Mining and Reclamation Priorities

State	Unfunded Costs	Funded Costs	Completed Costs	Total Costs
Alabama	423,254,768	14,538,382	70,284,497	508,077,647
Alaska	59,856,609	2,202,000	17,948,921	80,007,530
Arkansas	21,900,059	3,350,999	32,988,615	58,239,673
Arizona	0	0	334,520	334,520
Colorado	78,451,002	6,870,268	45,739,006	131,060,276
Illinois	122,034,648	11,708,760	170,084,482	303,827,890
Indiana	105,231,421	19,552,837	115,905,988	240,690,246
Kansas	248,870,737	42,497	30,341,457	279,254,691
Kentucky	460,405,026	64,710,925	452,006,226	977,122,177
Louisiana	14,078,338	0	0	14,078,338
Maryland	63,367,736	780,801	32,346,883	96,495,420
Missouri	113,076,482	440,002	51,281,746	164,798,230
Montana	96,047,527	29,324,711	64,095,281	189,467,519
North Dakota	38,596,433	2,072,625	35,248,268	75,917,326
New Mexico	13,439,520	3,952,733	19,388,160	36,780,413

State	Unfunded Costs	Funded Costs	Completed Costs	Total Costs
Ohio	204,605,624	3,259,974	140,920,052	348,785,650
Oklahoma	143,833,075	1,082,000	33,122,293	178,037,368
Pennsylvania	5,020,558,962	116,529,962	539,091,667	5,676,180,591
Tennessee	43,403,495	173,000	35,769,668	79,346,163
Texas	22,796,152	7,819,045	31,755,516	62,370,713
Utah	6,710,319	1,211,600	20,062,617	27,984,536
Virginia	436,801,606	10,319,581	100,813,558	547,934,745
West Virginia	1,466,961,321	15,482,559	461,595,149	1,944,039,029
Wyoming	54,426,746	29,330,947	483,296,610	567,054,303

Source: *AMLs Inventory System 13*, December 2010

State severance tax estimates by coal region are shown inTable 4-17. Because severance taxes are a factor of both the quantities of coal extracted and the tax rates set by each state, the level of severance tax associated with underground and surface mining varies. The Appalachian Basin and Colorado Plateau realize greater revenues from underground mining than from surface mining. Considered overall, however, by far the greatest level of severance tax revenue is associated with surface mining in the Northern Rocky Mountains and Great Plains region, where estimated surface mining severance tax revenues equal three times the total revenues from surface and underground mining in all other regions. As a share of total state tax revenue, severance taxes contribute 12.9% in the Northern Rocky Mountains and Great Plains region, which compares with 0.7% in the Appalachian Basin region.

Table 4-17: Estimated State Coal-Related Severance Taxes by Region

Coal-Producing Regions	Estimated State Severance Taxes ($1,000)		
	Underground	Surface	Total
Appalachian Basin	61,389	42,049	103,439
Colorado Plateau	12,690	7,971	20,661
Gulf Coast	491	2,164	2,655
Illinois Basin	3,773	17,133	20,906
Northern Rocky Mountain and Great Plains	1,429	482,081	483,509
Northwest	0	0	0
Other Western Interior	121	412	534

Source: Calculations derived from state severance tax rates, EIA 2010a,b

Estimated state income taxes associated with coal mining industry employment in each region is shown inTable 4-18. In contrast with the relative level of revenues from severance taxes, income taxes from coal mining in the Northern Rocky Mountain and Great Plains region are at a low level and are only approximately one-tenth the net amount estimated for the Appalachian Basin region. At 0.1% of the USCB 2008 estimate of total income tax in the Appalachian Basin region, direct state income taxes from coal mine employees make up a small portion of all income tax revenues. This is consistent with the Gulf Region (0.1%) and the Northern Rocky Mountain and Great Plains (0.1%), while all other regions have lower percentages.

Table 4-18: Estimated State Coal-Related Income Taxes by Region

Coal-Producing Region	Estimated State Income Taxes ($1,000)		
	Underground	Surface	Total
Appalachian Basin	62,351	35,524	97,876
Colorado Plateau	8,664	3,738	12,403
Gulf Coast	3,630	5,842	9,472
Illinois Basin	13,714	5,035	18,750
Northern Rocky Mountain/Great Plains	404	9,811	10,216
Northwest	0	0	0
Other Western Interior	137	463	599

Source: Calculations derived from BLS, 2010; EIA, 2010a, 2010b; Tax Foundation, 2010.

Royalties are collected and distributed to the state at a rate of approximately 50% of collected royalties, bonuses, and rents, and at a rate of 100% back to tribes for deposits located on tribal lands. Table 4-19 lists the federal and tribal royalties and the estimated state disbursement from the federal royalties. Tribes in Arizona, Montana, and New Mexico receive substantial royalties from coal, especially in Arizona. Wyoming is the largest recipient of coal royalties, with an estimated disbursement of $300.5 million from FY 2008 sales volumes.

Table 4-19: Coal Royalties for FY 2008 by State and Estimated State Disbursement

State	Tribal Royalties ($1,000)	Federal Royalties ($1,000)	Estimated State Disbursements ($1,000)
Appalachian Basin/Illinois Basin			
Kentucky	0	2,449	1,225
Colorado Plateau			
Colorado	0	75,134	37,567
New Mexico	43,169	15,752	7,876
Arizona	33,824	0	0
Utah	0	34,985	17,492
Gulf Region			
Alabama	0	1,415	707
Northern Rocky Mountain/Great Plains			
Wyoming	0	600,974	300,487
Montana	11,282	44,296	22,148
Other Western Interior			
Oklahoma	0	4,740	2,370

Source: Calculated from Office of Natural Resources Revenue ONRR, 2010.

4.2.9.6 Environmental Justice

The current guidance, which was previously analyzed for environmental justice concerns, was found not to create disproportionate effects under the Final Environmental Impact Statement for Excess Spoil Minimization — Stream Buffer Zone (September 2008).

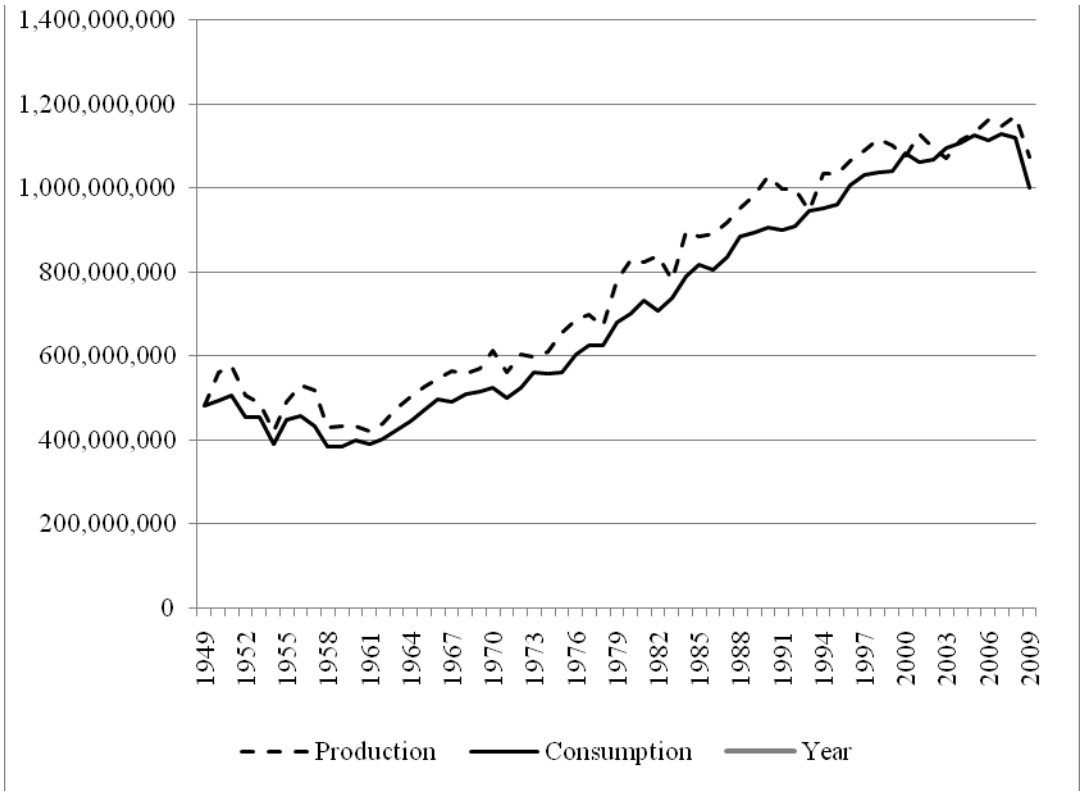
4.2.10 Long Term Historic National Coal Production and Consumption Trends

An important trend to bear in mind related to the two analyzed scenarios is how the proposed SPR could impact coal mining production and consumption levels. Figure 4-1 shows these trends since 1949, or over the past 60 years.

The overall picture is one of a fairly consistent relationship between coal production and consumption. From a macro analysis standpoint, SMCRA, which was adopted in 1977, has had no observable negative impact on the overall national coal supply and demand numbers. There have been significant regional shifts in coal production, which are discussed below.

If this relationship continues in the future, coupled with a flat/slow-growth outlook for coal in the future, it is possible that the proposed SPR may have little impact on the coal mining industry itself, especially if the industry is capable of passing along the additional costs created by the SPR to its customers. Historically, this has been the case, and major coal users (electric power generators and steel producers) have been able to pass these costs on to their customers.

Figure 4-1: Long-Term Production and Consumption Trends in U.S. Coal Industry



Source: EIA, Annual Coal Outlook Report, 2010.

The scope of the RIA did not include an analysis of the economic impact of SPR compliance costs on the electric power sector and other major coal using industries and final business and household consumers. Once a final rule exists, the final RIA should include this analysis to understand the overall effects of the rule on these economic sectors. **Error! Reference source**

not found. Table 4-20 identifies major trends in coal demand over the past five years (2005-2009).

Total coal consumption dropped by more than 11 percent during the 2005-2009 period, with the largest decline occurring in 2009, which was triggered by the economic recession that depressed demand by electric power generators and other markets, as shown in Table 4-20.

Table 4-20: U.S. Coal Consumption by Major Sector

Market	2005	2006	2007	2008	2009	2005-2009 % Change
Consumption by Sector						
Electric Power	1,037.50	1,026.60	1,045.10	1,040.60	936.5	-9.73
Coke Plants	23.4	23	22.7	22.1	15.3	-34.62
Other Industrial Plants	60.3	59.5	56.6	54.4	45.4	-24.71
Residential/Commercial Users	4.7	3.2	3.5	3.5	3.2	-31.91
Total	1,126.00	1,112.30	1,128.00	1,120.50	1,000.40	-11.15

Source: EIA. 2009. U.S. coal supply and demand review, 2009.

The most significant observation regarding the coal market is its continued dominance by electric power generation, which has historically accounted for 90 to 94 percent of total coal demand.

4.2.11 Regional Coal Production Shifts, 2005-2009 TO BE UPDATED W/PRODUCTION SHIFT ANALYSIS

Cola Production from 2005 through 2009 is shown in Table 4-21. Production data **Error! Reference source not found.**indicate a steady shift away from Eastern coal supplies and growing reliance on Western supply sources. This shift has been under way for some time, and is motivated by many factors, including the cleaner quality of Western coal and the faster growth of Western coal markets than those in the East.

U.S. coal production decreased considerably in 2009, dropping by 8.5 percent to 1,072.8 million short tons, 99.1 million short tons less than the 2008 production total. The decline in coal production in 2009 was the largest percent decline since 1958 (when production declined by 16.7 percent) and the largest tonnage decline since 1949 (when production declined by 176.1 million short tons).

Although total U.S. coal production was lower in 2009, one (Interior Region) of the three coal-producing regions had a slight increase in coal production, while the other two had large declines. Aside from refuse production, the Appalachian and Western Regions had decreases in their respective 2009 production levels of 13.0 percent and 7.7 percent, while the Interior Region remained essentially unchanged. The decrease in the Appalachian Region production was 50.9 million short tons, while the decrease in Western Region production in 2009 was 49.1 million short tons. Coal production in the Interior Region increased, but by only 216 thousand short tons.

Table 4-21: Coal Production in the United States

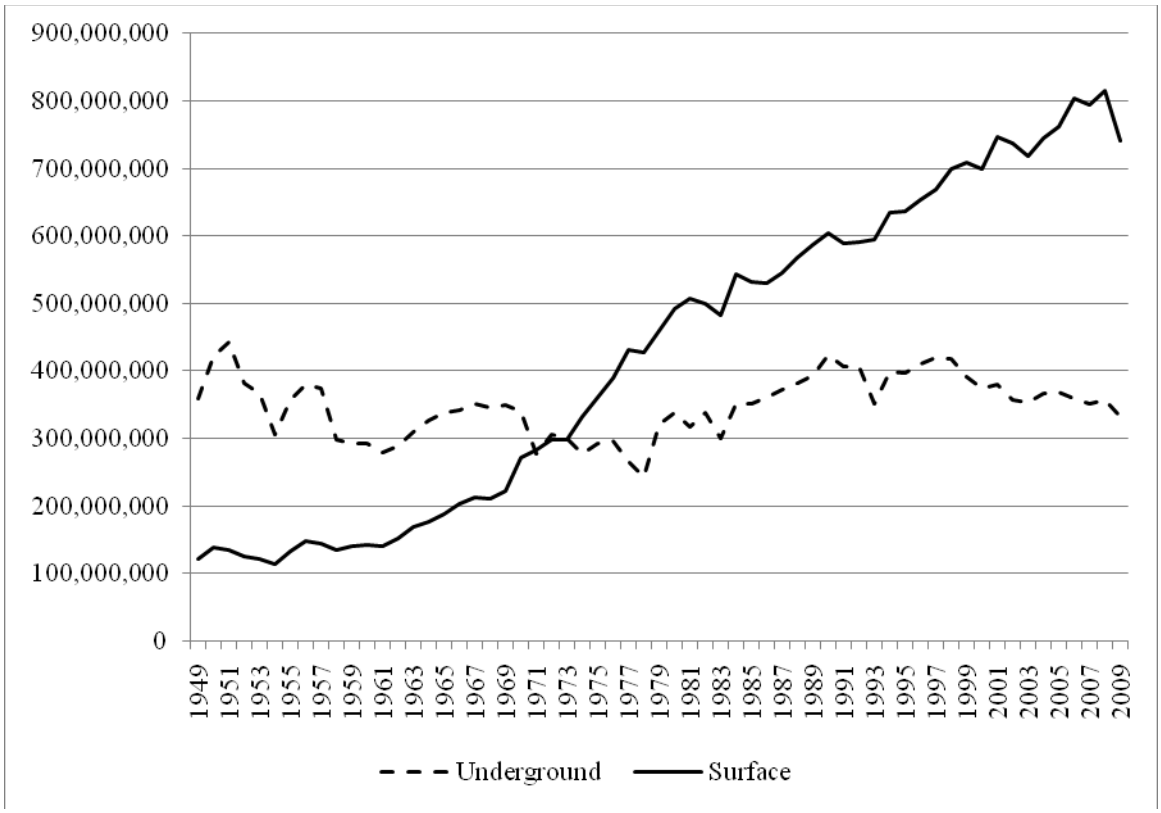
Area	2005	2006	2007	2008	2009	2005-2009 % Change
Production by Region						
Appalachia	396.7	391.2	377.8	390.2	339.3	-14.47
Northern Appalachia	140	136.2	132.1	135.6	126.5	-9.64
Central Appalachia	235.3	236.1	226.2	234	194	-17.55
Southern Appalachia	21.3	18.8	19.3	20.6	18.7	-12.21
Interior	149.2	151.4	146.7	146.6	146.8	-1.61
Western	585	619.4	621	633.6	584.5	-0.09
Refuse Recovery	0.7	0.8	1.2	1.4	2.1	200.00
Total	1,131.50	1,162.80	1,146.60	1,171.80	1,072.80	-5.19

Source: EIA, U.S. coal supply and demand review, 2009.

4.2.12 Surface and Underground Mining Trends

Figure 4-2 below shows coal production trends by major mining method since 1949. Since the early 1970s, surface mining has grown in importance as the economics of the coal mining industry shifted, and more labor-intensive underground mining took a lesser priority to more productive surface mining methods. The enactment of the SMCRA and creation of OSM in 1977 appears to have no negative impact on surface mining production levels. To the contrary, surface mining has steadily grown over the past 33 years.

Figure 4-2: Long-Term U.S. Trend in Surface and Underground Mining



NOTE: THE LATEST REGIONAL PRODUCTION SHIFT TABLES FROM THE EIS SHOULD BE INSERTED HERE WITH SOME DISCUSSION

U.S. Coal Supply. Coal production during the first 6 months of 2010 fell by 2.5 percent from the same period last year despite a 5.4-percent increase in U.S. coal consumption. A drawdown in stocks, particularly in the electric power sector, met the demand increase (U.S. Electric Power Sector Coal Stocks Chart). Estimated coal production increases in the second half of 2010 contributed to 2010 annual growth of 1.0 percent. EIA projects coal production in 2011 will remain relatively flat as coal consumption shows little change (U.S. Annual Coal Production Chart). The projected increase in coal consumption in 2012 leads to a forecast 3.6 percent increase in coal production.

U.S. Coal Trade. Strong global demand for coal, particularly metallurgical coal used to produce steel, resulted in sharp increases in U.S. coal exports in 2010 to an average of 7.3 percent of production. Metallurgical coal exports nearly doubled in the first half of 2010 compared with the first half of 2009, and metallurgical coal's share of total coal exports has grown from 52 percent in 2008 to almost 70 percent in 2010. Flooding in Australia has greatly affected the amount of metallurgical coal available on the world market, and EIA expects U.S. metallurgical coal exports to increase in 2011 by 7.3 percent. In 2012, forecast U.S. coal exports fall back to more recent levels (about 80 million short tons) as other major coal-exporting countries increase their supply to the global coal market.

4.2.13 Critical Coal-Mining Industry Issues, Trends and Opportunities

The coal industry faces several critical issues.

Demand Closely Associated with Electricity Generation. Demand for coal depends on the demand for electricity, which depends on the health of the U.S. economy. The electric power sector accounts for more than 94 percent of U.S. coal consumption. However, many new power plants are built to use natural gas or other fuels instead of coal.

Prices Linked to Alternative Energy Costs. Coal prices are generally more stable than other prices, but can change by 20 percent or more in a year. To be competitive, coal must be priced less than natural gas, which burns cleaner.

Vulnerability to Electrical Industry Regulations. Coal suppliers are directly affected when compliance with environmental regulations forces electricity generators to make major renovations to or close plants. Some older electric power plants function too uneconomically to support the cost of major upgrades in pollution control technology.

High Dependence on Few Customers. Many smaller coal producers sell most of their production to a small number of customers, often just one. With consolidation within the electric utility industry, even large coal producers may rely on just a few large customers. Because of the high cost of transporting coal, many coal producers sell within a limited market area, making each customer highly important to revenue.

Mining Engineer Shortage. Experts believe that the number of mining engineering graduates in the United States needs to increase dramatically over the next decade to prevent shortages. Despite the need, the United States has fewer than 20 universities that offer degrees in mining engineering. Some graduates find working in the remote areas where coal mining takes place undesirable, creating a recruiting challenge for companies.

Shift to Western Coal. Western coal now accounts for nearly 60 percent of all U.S. production, up from one-third in 1990. Greater efficiencies in mining technology and rail transportation and tighter pollution controls have made developing the coal deposits of the Powder River Basin in Wyoming, where large seams of coal lie approximately 100 feet under the surface, more economical. Most of this coal is classified as “subbituminous,” with low heat content (8,500 to 9,000 Btu per pound), but it also has a low-sulfur content.

Reservoirs for GHG Storage. Natural underground reservoirs are being researched as possible “storage sites” for GHG emitted from power plants that burn coal. If the approach proves feasible, it could help mitigate environmental concerns regarding coal use. Though challenged by some environmental experts, deep saline reservoirs could hold all of the CO_2emitted from the nation’s coal-burning power plants over the next 100 years.

Methane Diversification. A growing number of oil and gas companies are interested in the nonconventional energy source coalbed methane (CBM), which is a form of natural gas trapped within coal seams. Parts of the United States have experienced a surge in CBM drilling in recent years. Special federal tax credits, high gas prices, and shrinking conventional gas supplies have played a part in CBM activity.

Coal Gasification and Liquefaction. Although still uneconomical, several demonstration plants are refining the technology of processing coal into cleaner-burning liquid and gas products. Because the process requires large investments and currently has restricted yields, liquefied and gasified coal plants are deemed unfeasible by many investors. Liquefied and gasified coal can also be used as feedstock for various chemical- manufacturing processes.

Cost Advantage over Other Fossil Fuels. The greater price volatility of crude oil and natural gas makes coal attractive as a long-term source for generating electricity. Coal is so much less expensive than equivalent amounts of oil and natural gas that customers can make substantial investments in new pollution control technology and still have lower overall costs.

Metallurgical Coal Outlook. The demand for metallurgical coal is associated with the level of activity in the steel industry. Metallurgical, or coking, coal is first converted to coke through heating the coal in an oxygen-free environment. After the coke is produced, it is added to iron ore in another high-temperature environment to produce iron. Every ton of steel made in a traditional blast furnace requires 0.6 ton of metallurgical coal, according to the World Coal Institute. Approximately 66 percent of all steel is manufactured using this method. The global production of steel in July 2010 totaled 115 million metric tons, a 9.6 percent increase on a year-over-year basis. Capacity utilization was 75.1 percent in July 2010, up on a year-over-year basis, but a sequential decrease from capacity utilization of 80.4 percent in June 2010. World seaborne or export demand for metallurgical coal is expected to increase 20 percent in 2010 over 2009, with strong demand coming from Asia and South America. The largest importers of metallurgical coal in 2010 include China (44 million tons), India (30 million tons), and Brazil (14 million tons). Japan, Korea, and Taiwan will require another 94 million tons in 2010. World seaborne supply of metallurgical coal is expected to increase by 13 percent in 2010 over 2009, with supply growth coming from the United States and Australia. Many companies have been adding capacity. For example, Massey Energy recently announced that the company is developing a new mine to produce metallurgical coal in West Virginia. The company will spend $100 million to $160 million through 2012 at the Rowland reserve.

4.2.14 IMPLAN Baseline Analysis (Nation and Coal Regions)

Using classic input-output analysis in combination with regional specific Social Accounting Matrices and Multiplier Models, Impact Analysis for Planning (IMPLAN) provides a highly accurate and adaptable model for its users. Appendix 5 includes the baseline IMPLAN analysis.

The IMPLAN database contains county, state, zip code, and federal economic statistics which are specialized by region, not estimated from national averages and can be used to measure the effect on a regional or local economy of a given change or event in the economy's activity.

Social Accounting: IMPLAN's Social Accounting System describes transactions that occur between producers, and intermediate and final consumers using a Social Accounting Matrix. One of the important aspects of Social Accounts is that they also examine non-market transactions, such as transfer payments between institutions. Other examples of these types of transactions would include government to household transfers in the form of unemployment benefits, or household to government transfers in the form of taxes. Because Social Accounting Systems examine all the aspects of a local economy, they provide a more complete and accurate "snapshot" of the economy and its spending patterns.

Multipliers: Multipliers are a numeric way of describing the secondary impacts stemming from a change. For example, an employment multiplier of 1.8 would suggest that for every 10 employees hired in the given industry, 8 additional jobs would be created in other industries, such that 18 total jobs would be added to the given economic region.

The Multiplier Model is derived mathematically using the input-output model and Social Accounting formats. The Social Accounting System provides the framework for the predictive Multiplier Model used in economic impact studies. Purchases for final use drive the model. Industries that produce goods and services for consumer consumption must purchase products, raw materials, and services from other companies to create their product. These vendors must also procure goods and services. This cycle continues until all the money is leaked from the region's economy.

There are three types of effects measured with a multiplier: the direct, the indirect, and the induced effects. The direct effect is the known or predicted change in the local economy that is to be studied. The indirect effect is the business to business transactions required to satisfy the direct effect. Finally, the induced effect is derived from local spending on goods and services by people working to satisfy the direct and indirect effects.

1. Direct effects take place only in the industry immediately affected.
2. Indirect effects concern inter-industry transactions.
3. Induced effects measure the effects of the changes in household income.
4. Total Impacts the total changes to the original economy as the result of a defined event; i.e., Direct effects + Indirect effects + Induced effects = Total Impacts

In this RIA, the IMPLAN model was used to analyze the impact of the baseline coal-mining industry at the U.S. (national) and major coal-mining region levels. The base year for this analysis was 2008, which is consistent with the baseline year used for EIS and RIA in general.

4.2.14.1 Baseline Economic Impacts of the Coal Mining Industry

Table 4-22 below shows the baseline (2008) economic output contribution of the coal mining industry at the national economy and regional coal-producing region levels.

The baseline economic output impact data shows that:

1. Appalachia is dominant in terms of the economic impact of the coal mining industry today, accounting for $44.8 billion of the total $90.8 billion national economic output of coal mining.

2. The coal-producing regions combined account for $63.7 billion of the total $90.8 billion national economic output of coal mining.

3. Of the coal mining industry's total national economic output of $90.8 billion, $36.1 billion of that total output occurs in the coal mining industry itself (defined as direct impact); $25.6 billion occurs in supplier and coal consuming industries (defined as indirect impact); and $29 billion occurs as a result of the

spending of the income generated by coal mining employment directly and indirectly (defined as induced impact).

4. It is important to note that non-coal producing states are impacted by the coal mining industry in terms of indirect impacts ($11.7 billion nationally) and induced impacts ($15.4 billion). These impacts are attributed to industries in non-coal producing states that supply the coal mining industry with goods and services or use coal in their industries.

Table 4-22: Baseline National and Regional Economic Output Impact of the Coal Mining Industry

2008 BASELINE NATIONAL AND REGIONAL ECONOMIC IMPACT
Total of All Sectors
Economic Output in Dollars Impacts

Region	Direct	Indirect	Induced	Total
Appalachian Basin	$24,199,311,352	$10,659,005,009	$9,959,667,361	$44,817,983,722
Colorado Plateau	$2,667,500,289	$790,511,855	$944,499,554	$4,402,511,698
Illinois Basin	$3,154,871,460	$1,020,822,561	$1,225,750,768	$5,401,444,790
Northern Rocky Mts. and Great Plains	$3,885,893,361	$851,536,312	$819,582,732	$5,557,012,405
Northwest	$12,322,385	$2,851,887	$2,840,067	$18,014,340
Other Western Interior	$438,866,540	$116,809,827	$136,458,859	$692,135,226
Gulf Region	$1,673,941,449	$492,762,867	$592,115,043	$2,758,819,359
Coal Regions Total	$36,032,706,836	$13,934,300,318	$13,680,914,384	$63,647,921,540
Non-Coal Producing States Totals	$72,401,545	$11,710,485,940	$15,381,652,156	$27,164,539,639
Nation	$36,105,108,381	$25,644,786,258	$29,062,566,540	$90,812,461,179

The baseline employment impact data shows that:

1. Appalachia is dominant in terms of the employment impact of the coal mining industry today, accounting for 174,055 of the total 359,958 national employment impact of coal mining.
2. The coal-producing regions combined account for 242,818 of the total 359,958 employment impact of coal mining.
3. Of the coal mining industry's total national employment impact of 359,958, 81,041 of that employment impact occurs in the coal mining industry itself (defined as direct impact); 95,522 occurs in supplier and coal consuming industries (defined as indirect impact); and 183,365 occurs as a result of the spending of the income generated by coal mining employment directly and indirectly (defined as induced impact).
4. It is important to note that non-coal producing states are impacted by the coal mining industry in terms of indirect employment impacts (37,380 nationally) and induced

impacts (79,572 nationally). These impacts are attributed to industries in non-coal producing states that supply the coal mining industry with goods and services or use coal in their industries.

Table 4-23 below shows the baseline (2008) employment contribution of the coal mining industry at the national economy and regional coal-producing region levels.

Table 4-23: Baseline National and Regional Employment Impact of the Coal Mining Industry

2008 BASELINE NATIONAL AND REGIONAL ECONOMIC IMPACT
Total of All Sectors
Employment Impacts

Region	Direct	Indirect	Induced	Total
Appalachian Basin	55,961	43,351	74,743	174,055
Colorado Plateau	6,118	3,818	7,328	17,264
Illinois Basin	6,403	4,202	8,790	19,395
Northern Rocky Mountains and Great Plains	8,455	4,133	7,447	20,035
Northwest	27	11	21	60
Other Western Interior	775	558	1,135	2,468
Gulf Region	3,143	2,069	4,329	9,541
Coal Producing Regions Total	80,882	58,142	103,793	242,818
Non-Coal Producing States Total	159	37,380	79,572	117,110
Nation	81,041	95,522	183,365	359,928

4.2.15 State Coal Industry Profile

As a part of the analysis of baseline economic conditions, an analysis of the coal-mining industry in each of the coal-producing states was conducted. A summary of this analysis is provided in Appendix 6.

Two major observations may be made about this analysis. First, the extent of coal mining activities varies widely in the states, and therefore the baseline economic significance of coal mining to these state economies varies widely.

The industry is very important for example to the economies of smaller, more rural states like West Virginia, Kentucky, Pennsylvania, and Wyoming. It is less important to the large industrial and urban states like Ohio, Pennsylvania, and Illinois.

Secondly, coal mining activities in general are found in rural counties in all coal producing states, which suggests that the industry's economic significance is of greater importance to rural economies than urban economies. Coal mining takes on a greater importance to urban areas where coal is a principal fuel used in electric power generation for urban areas.

The importance of the state coal mining industry profiles is that they reflect an understanding of and appreciation for the economic role of coal in the various states.

4.3 BASELINE ENVIRONMENTAL CONSIDERATIONS

CAPTURE INFO FROM EIS

4.4 BENEFITS

(TO BE DEVELOPED WITH OSM)

4.5 COSTS

(TO BE DEVELOPED WITH OSM)

4.6 TRANSFERS

(FROM EIS)

4.7 OTHER EFFECTS

(FROM EIS)

4.8 NET BENEFIT OR COST

CONCEPTUAL - TO BE COMPLETED

5 Analysis of Rule Alternatives

5.1 ALTERNATIVE 5 (PROPOSED RULE)

5.1.1 Benefits

TO BE COMPLETED WITH OSM

5.1.2 Costs

TO BE COMPLETED WITH OSM

5.1.3 Transfers

TO BE COMPLETED

5.1.4 Other Effects

(RFA/Small Business Impacts, Tribal Impacts, Royalties, Others) **TO BE COMPLETED**

5.1.5 Net Benefit or Cost

TO BE COMPLETED

5.2 ALTERNATIVE 2 (MOST ENVIRONMENTALLY STRINGENT)

5.2.1 Benefits

TO BE COMPLETED WITH OSM

5.2.2 Costs

TO BE COMPLETED WITH OSM

5.2.3 Transfers

TO BE COMPLETED

5.2.4 Other Effects

(RFA/Small Business Impacts, Tribal Impacts, Royalties, Others) **TO BE COMPLETED**

TO BE COMPLETED

5.2.5 Net Benefit or Cost

TO BE COMPLETED

6 Summary

6.1 DISTRIBUTIONAL AFFECTS[41]

Table 6-1 serves as an overall summary of the economic costs, benefits, and other effects of the proposed Stream Protection Rule.

Table 6-1: Cost-Benefit Summary for Proposed Stream Protection Rule for the 13.5-Year Period of Rule Implementation

THIS WILL BE REWORKED TO DESCRIBE THE NET COSTS AND BENEFITS OF THE POLICY ACROSS THE POPULATION AND ECONOMY. WE HAVE NO 'UPDATED' QUANTITATIVE OR MONETIZED NUMBERS FOR THE VARIOUS CELLS.

Category	Proposed Preferred Rule)	Baseline Situation	Most Environmentally Stringent	Source Citation
Benefits: **Annualized Monetized Benefits** **Annualized Quantified, but Non-Monetized Benefits** **Non-Quantified Benefits/Qualitative Benefits**				

41 The overall summary of results of the CBA will use the required 3% and 7% discount factors to bring the numbers to present value.

Category	Proposed Preferred Rule)	Baseline Situation	Most Environmentally Stringent	Source Citation
Costs: **Annualized Monetized Costs** **Annualized Quantified, but Non-Monetized Costs** **Non-Quantified Costs/Qualitative Costs**				
Transfers: **Annualized Monetized Transfers** **From Whom to Whom** **Annualized Monetized Transfers (Off Budget)**				

Category	Proposed Preferred Rule)	Baseline Situation	Most Environmentally Stringent	Source Citation
Effects: **Effects on State, Local, and Tribal Governments** **Effects on Small Businesses** **Effects on Wages** **Effects on Growth**				

Other summarizing points

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APPENDIX 1

ENVIRONMENTAL VALUATION SOURCES

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Table A1-1 provides a summary of the household and individual WTP and overall benefits of aquatic ecological services. Costanza, et al. provided one of the first large-scale evaluations of ecosystem services, providing value to services which did not have a full market-level valuation (Costanza et al. 1997). In this study, Costanza et al. indicated that the estimated natural capital value of lakes and rivers to the globe was approximately $1,700 per hectare (ha) ($689 per acre) (Costanza et al 1997.) Holmes, Bergstrom, Huszar, Kask, and Orr (2004) determined that riparian restoration activities along the Little Tennessee River were valued at $89.50 per linear foot of restoration activities. Loomis, Kent, Strange, Fausch, and Covish (2000) determined that households were willing to provide $252 per year for restoration activities along the Platte River, which provided a consumer surplus well in excess (41.8% to over 400% greater) of the approximately $13.4 million that would be required to fund Conservation Reserve Program (CRP) easements for riparian buffers and to lease water for continued in-stream flows.

Table A1-1: Willingness-to-Pay for Aquatic Ecological Services

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Amigues, Boulatoff, Desaigues, Gauthier, & Keith	2002	Garonne River Toulouse, France	riparian buffer preservation	26-28	Mean of those that would pay
Amigues, Boulatoff, Desaigues, Gauthier, & Keith	2002	Garonne River Toulouse, France	riparian buffer preservation	13	Mean of entire sample
Berrens, Bohara, Jenkins-Smith, Silva, Ganderton, & Brookshire	1998	New Mexico	In-stream flows	80	Mean of positive answers
Berrens, Bohara, Jenkins-Smith, Silva, Ganderton, & Brookshire	1998	New Mexico	In-stream flows	-6	Mean of negative answers
Bowman, Thompson, & Colletti	2009	Cedar Rapids, IA	conservation features contribution to housing prices	21,303	Contribution of adjacent streams to housing values
Costanza, et al.	1997	Global	value of natural capital – lakes and rivers	1,700	Per hectare per year
Holmes, Bergstrom, Huszar, Kask, & Orr	2004	Little Tennessee River	riparian restoration activities	89.50	Per linear foot present value benefits of full implementation scenario
Holmes, Bergstrom, Huszar, Kask, & Orr	2004	Little Tennessee River	riparian restoration activities	5.60	Per household per mile of restoration
Kealy & Turner	1993	Adirondacks	preservation of aquatic system	12.79-18	Mean one-time payment
Loomis	1989	California	Mono Lake preservation	4.72-11.42	Per month
Loomis, Kent, Strange, Fausch, & Covish	2000	Platte River	restoration of riparian ecological services	252	Per household per year

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Loomis, Kent, Strange, Fausch, & Covich	2000	Platte River	riparian restoration activities	21	Per household per month
Loomis, Kent, Strange, Fausch, & Covich	2000	Platte River	riparian restoration activities	19-70 million	Annually all households
Loomis, Kent, Strange, Fausch, & Covich	2000	Platte River	riparian restoration activities	1.13 million (water leasing) + 12.3 million CRP easements annually	Actual costs of activities in the basin

Table A1-2 provides a list of studies conducted to determine the value of groundwater clean-up efforts through AC estimates and the market value of in-storage water.

Table A1-2: Willingness-to-Pay for Groundwater Ecological Services

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Abdalla, Roach, & Epp	1992	Pennsylvania	water quality – water contamination	0.40	Per household per week
Abdalla, Roach, & Epp	1992	Pennsylvania	water quality – water contamination	61,313.29-131,334.06	Total over all households over 88 weeks
McClelland, Schulze, Lazo, Waldman, Doyle, Elliott, & Irwin	1992	US	groundwater protection	2.81-3.54	non-use value of groundwater
McClelland, Schulze, Lazo, Waldman, Doyle, Elliott, & Irwin	1992	US	groundwater protection	1.13-13.34	use value of groundwater as WTP for cleaning
Torell, Libbin, & Miller	1990	Ogallala Aquifer	market value of water (1979-1986)	3.93	Average value per acre foot of saturated thickness
Torell, Libbin, & Miller	1990	Ogallala Aquifer	market value of water (1979-1986) – New Mexico	8.35	Average value per acre foot of saturated thickness
Torell, Libbin, & Miller	1990	Ogallala Aquifer	market value of water (1979-1986) – Oklahoma	1.52	Average value per acre foot of saturated thickness
Torell, Libbin, & Miller	1990	Ogallala Aquifer	market value of water (1979-1986) – Colorado North	5.45	Average value per acre foot of saturated thickness
Torell, Libbin, & Miller	1990	Ogallala Aquifer	market value of water (1979-1986) – Colorado South	2.99	Average value per acre foot of saturated thickness

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Torell, Libbin, & Miller	1990	Ogallala Aquifer	market value of water (1979-1986) – Kansas	2.40	Average value per acre foot of saturated thickness
Torell, Libbin, & Miller	1990	Ogallala Aquifer	market value of water (1979-1986) - Nebraska	2.89	Average value per acre foot of saturated thickness

Table A1-3 lists the values associated with water quality components, such as clean enough to boat, fish, and swim. Carson and Mitchell (1993) determined that households would willing to annually contribute up to $242 to change water quality up to swimmable (the highest water quality standard). Holmes (1988) found that it costs between $35 to 661 million per year for water treatment costs associated with soil erosion. Johnston, Besedin, Iovanna, Miller, Wardwell, and Ranson (2005) indicated that non-users would have WTP between $6 to $9 to improve fish habitat by 0.5, 1.0, and 2.0 steps in habitat improvement. Along similar lines, VanHoutven, Powers, and Pattanayak (2007) found that households were willing to pay between $3 to $132 annually for water quality improvement 1, 3, and 6 steps higher than their current water quality. Ribaudo (1989) from a study of CRP acres, indicated that targeting for water quality benefits could result in values per acre ranging from $42 per acre in the Northern Plain Farm Production Region to as high as $306 per acre in the Delta Farm Production Region.

Table A1-3: Willingness-to-Pay for or Value of Water Quality Ecological Services

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Carson & Mitchell	1993	US	water quality benefits – boatable	93	annual household contribution
Carson & Mitchell	1993	US	water quality benefits – fishable	70	annual household contribution
Carson & Mitchell	1993	US	water quality benefits – swimmable	78	annual household contribution
Carson & Mitchell	1993	US	water quality benefits - total	242	annual household contribution
Corrigan, Egan, & Downing	2007	Clear Lake, IA	water quality improvements – small	139	Per visitor
Corrigan, Egan, & Downing	2007	Clear Lake, IA	water quality improvements - large	347	Per visitor
Holmes	1988	US	water turbidity due to soil erosion	35-661 million	Per year
Holmes	1988	US	water turbidity due to soil erosion	$4.40 - $82.34	Per million gallons treatment costs
Holmes	1988	California (ASA 1806)	water turbidity due to soil erosion	1.4585 million	incremental benefit from 10% change in sediment loading
Holmes	1988	California (ASA 1804)	water turbidity due to soil erosion	0.3358 million	incremental benefit from 10% change in sediment loading

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Holmes	1988	Great Lakes (ASA 408)	water turbidity due to soil erosion	0.2388 million	incremental benefit from 10% change in sediment loading
Holmes	1988	Missouri (ASA 1009)	water turbidity due to soil erosion	0.1956 million	incremental benefit from 10% change in sediment loading
Holmes	1988	Missouri (ASA 1005)	water turbidity due to soil erosion	0.1323 million	incremental benefit from 10% change in sediment loading
Holmes	1988	Arkansas-White-Red (ASA 1102)	water turbidity due to soil erosion	0.1322 million	incremental benefit from 10% change in sediment loading
Holmes	1988	Upper Mississippi (ASA 701)	water turbidity due to soil erosion	0.1303 million	incremental benefit from 10% change in sediment loading
Holmes	1988	Great Lakes (ASA 406)	water turbidity due to soil erosion	0.1264 million	incremental benefit from 10% change in sediment loading
Holmes	1988	Arkansas-White-Red (ASA 1103)	water turbidity due to soil erosion	0.1249 million	incremental benefit from 10% change in sediment loading
Holmes	1988	Missouri (ASA 1007)	water turbidity due to soil erosion	0.1133 million	incremental benefit from 10% change in sediment loading
Johnston, Besedin, Iovanna, Miller, Wardwell, & Ranson	2005	US	water quality for fish habitat improvements – (0.5 grade improvement)	5.83-6.89	Non-user
Johnston, Besedin, Iovanna, Miller, Wardwell, & Ranson	2005	US	water quality for fish habitat improvements – (1.0 grade improvement)	6.82-7.65	Non-user
Johnston, Besedin, Iovanna, Miller, Wardwell, & Ranson	2005	US	water quality for fish habitat improvements – (2.0 grade improvement)	7.99-9.44	Non-user
Laughland, Musser, Shortle, & Musser	1996	Pennsylvania	water treatment costs	14.14-36.33	Lower bound – upper bound household avoidance costs
Laughland, Musser, Shortle, & Musser	1996	Pennsylvania	water treatment costs	18.44	Mean
Nunes & van den Bergh[1]	2001	Monongahela River basin	preservation of water quality	21-58	Users
Nunes & van den Bergh[1]	2001	Monongahela River basin	preservation of water quality	14-53	Non-users
Ribaudo	1989	Appalachia FPR	CRP-potential benefits to water quality (Water Quality Targeting)	221	Per acre

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Ribaudo	1989	Corn Belt FPR	CRP-potential benefits to water quality (Water Quality Targeting)	82	Per acre
Ribaudo	1989	Delta FPR	CRP-potential benefits to water quality (Water Quality Targeting)	306	Per acre
Ribaudo	1989	Lake States FPR	CRP-potential benefits to water quality (Water Quality Targeting)	170	Per acre
Ribaudo	1989	Mountain FPR	CRP-potential benefits to water quality (Water Quality Targeting)	62	Per acre
Ribaudo	1989	Northeast FPR	CRP-potential benefits to water quality (Water Quality Targeting)	270	Per acre
Ribaudo	1989	Northern Plains FPR	CRP-potential benefits to water quality (Water Quality Targeting)	42	Per acre
Ribaudo	1989	Pacific FPR	CRP-potential benefits to water quality (Water Quality Targeting)	124	Per acre
Ribaudo	1989	Southeast FPR	CRP-potential benefits to water quality (Water Quality Targeting)	169	Per acre
Ribaudo	1989	Southern Plains FPR	CRP-potential benefits to water quality (Water Quality Targeting)	64	Per acre
Ribaudo	1989	Appalachia FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	357	Per acre
Ribaudo	1989	Corn Belt FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	89	Per acre
Ribaudo	1989	Delta FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	357	Per acre
Ribaudo	1989	Lake States FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	163	Per acre
Ribaudo	1989	Mountain FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	70	Per acre
Ribaudo	1989	Northeast FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	237	Per acre
Ribaudo	1989	Northern Plains FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	47	Per acre

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Ribaudo	1989	Pacific FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	192	Per acre
Ribaudo	1989	Southeast FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	160	Per acre
Ribaudo	1989	Southern Plains FPR	CRP-potential benefits to water quality Damages per Ton of Erosion Targeting)	86	Per acre
Ribaudo	1989	Appalachia FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	156	Per acre
Ribaudo	1989	Corn Belt FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	86	Per acre
Ribaudo	1989	Delta FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	356	Per acre
Ribaudo	1989	Lake States FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	165	Per acre
Ribaudo	1989	Mountain FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	69	Per acre
Ribaudo	1989	Northeast FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	332	Per acre
Ribaudo	1989	Northern Plains FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	44	Per acre
Ribaudo	1989	Pacific FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	128	Per acre
Ribaudo	1989	Southeast FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	1,661	Per acre
Ribaudo	1989	Southern Plains FPR	CRP-potential benefits to water quality Damages per Cropland Acre from Erosion Targeting)	68	Per acre

Author	Year Published	Location	Ecological Services Valued	Willingness-to-Pay ($US)	Description of Values
Van Houtven, Powers, & Pattanayak	2007	US	water quality improvements – (1 step change)	3-58	Per year
Van Houtven, Powers, & Pattanayak	2007	US	water quality improvements – (3 step change)	32-87	Per year
Van Houtven, Powers, & Pattanayak	2007	US	water quality improvements – (6 step change)	75-132	Per year

[1] from Smith, V.K., and W.H. Desvousges, 1986. Measuring Water Quality Benefits. Kluwer Nijhoff Publishing, Dordrecht.

ASA - Aggregate Sub-Area Watershed
FPR – Farm Production Region

Table A1-4 lists the values associated with forest-related ecological services. Alig, Adams, and McCarl (1998) determined that the forest sector in the United States contributes approximately $2.4 trillion to domestic consumer surplus. McPherson, Nowak, Heisler, Grimmond, Souch, Grant & Rowntree (1997) found that urban trees and forests in Chicago absorbed enough air pollutants to avoid $9.2 million in health care and other pollution damage costs within the city. Costanza et al. (1997) estimated the ecological services value of temperate forests at approximately $894 per ha ($362 per acre). Ingraham and Foster (2008) determined that the value of forests within the U.S. National Wildlife Refuge System was approximately $850 per acre. Kramer, Holmes, and Haefele (2003) indicated that protection of the Southern Appalachian Spruce Fir forests was worth approximately $28 per respondent. Similarly, Walsh, Bjonback, Aiken, and Rosenthal determined that household has a WTP of $47 for forest quality protection.

Table A1-4: Willingness-to-Pay for or Value of Forest-Related Ecological Services

Author	Year Published	Location	Ecological Services Value	Willingness-to-Pay ($US)	Description of Values
Alig, Adams, & McCarl	1998	US Forest	Forest sector domestic consumer surplus	2.388 trillion	National value
Alig, Adams, & McCarl	1998	US Forest	Forest sector domestic producer surplus	0.230 trillion	National value
Alig, Adams, & McCarl	1998	US Forest	Forest sector net surplus	2.754 trillion	National value
Amirnejad, Khalilian, Assareh & Ahmadian[1]	2006	Costa Rica	existence Costa Rican tropical forest	238	Per hectare
Amirnejad, Khalilian, Assareh & Ahmadian[2]	2006	Sweden	preservation old growth forests	10-20	Per year
Amirnejad, Khalilian, Assareh & Ahmadian	2006	Iran	protection of northern forests – existence values	198.7	Per hectare
Amirnejad, Khalilian, Assareh & Ahmadian	2006	Iran	protection of northern forests – existence values	30.12	Per family

Author	Year Published	Location	Ecological Services Value	Willingness-to-Pay ($US)	Description of Values
Amirnejad, Khalilian, Assareh & Ahmadian	2006	Iran	protection of northern forests – existence values	376.5 million	Total
Costanza, et al.	1997	Global	value of natural capital – temperate forests	894	Per hectare per year
Gregory	2000	western Oregon	regeneration/human-wildlands interaction – forest fire protection (75% protection)	10.63-41.36	Per individual
Gregory	2000	western Oregon	regeneration/human-wildlands interaction – forest fire protection (50% protection)	6.92-26.53	Per individual
Gregory	2000	western Oregon	regeneration/human-wildlands interaction – forest fire protection (25% protection)	3.73-11.70	Per individual
Ingraham & Foster	2008	US National Wildlife Refuge System	wilderness area protection	850	Per acre per year
Kramer, Holmes, & Haefele	2003	Southern Appalachia Mountains Spruce-Fir Forests	forest ecosystem protection – use values	3.70	Per respondent
Kramer, Holmes, & Haefele	2003	Southern Appalachia Mountains Spruce Fir Forest	forest ecosystem protection – bequest values	8.55	Per respondent
Kramer, Holmes, & Haefele	2003	Southern Appalachia Mountains Spruce Fir Forests	forest ecosystem protection – existence values	16.24	Per respondent
Kramer, Holmes, & Haefele	2003	Southern Appalachia Mountains Spruce Fir Forests	forest ecosystem protection – total values	28.49	Per respondent
Kramer & Mercer	1997	worldwide	protection 5% of tropical rain forest	21-31	One-time payment per household
Loomis, Gonzalez-Caban, & Gregory	1996	Pacific Northwest	fire protection in old growth forests – habitat protection from wildfires	90/household	Per household

Author	Year Published	Location	Ecological Services Value	Willingness-to-Pay ($US)	Description of Values
Loomis, Gonzalez-Caban, & Gregory	1996	Pacific Northwest	fire protection in old growth forests – habitat protection from wildfire	28/ac of Northern Spotted Owl habitat protected	Per acre of Northern Spotted Owl protected habitat
McPherson, Nowak, Heisler, Grimmond, Souch, Grant, & Rowntree	1997	Chicago	air pollutant absorption of urban trees (AC s)	9.2 million	Total value to Chicago
Walsh, Bjonback, Aiken & Rosenthal	1990	US	forest quality protection – recreation use values	13	Per household
Walsh, Bjonback, Aiken & Rosenthal	1990	US	forest quality protection – option values	10	Per household
Walsh, Bjonback, Aiken & Rosenthal	1990	US	forest quality protection – existence values	10	Per household
Walsh, Bjonback, Aiken & Rosenthal	1990	US	forest quality protection – bequest values	14	Per household
Walsh, Bjonback, Aiken & Rosenthal	1990	US	forest quality protection – total values	47	Per household

[1] from Echeverria, J., M. Haarahan, R. Solorzano, 1995. Valuation of non-priced amenities provided by the biological resources within the Monterverde Cloud Forest Preserve, Costa Rica, Ecological Economics, 13, 43-52.
[2] from Kristom, B., 1999. Valuing Forests. MBG Press, Stockholm

Table A1-5 provides an overview of costs of different types of soil erosion and the benefits of programs such as CRP that help conserve soil. Clark (1985) found that soil erosion causes damages of approximately $4.1 billion in-stream and an additional $1.9 billion off stream. Huszar (1989) citing other studies in his analysis indicated that wind erosion in New Mexico would costs approximately $10 million per year to avoid on-site, but $458 million to avoid off-site. Williams, Tanaka, and Herbel (1993) found that farmers were willing to spend approximately $5 per acre to conserve the topsoil from 2.5 inches to 5 inches. Sullivan et al (2004) indicated that CRP provides per acre benefits valued between $5 to $44 depending upon the region in the aversion of soil erosion.

Table A1-5: Willingness-to-Pay for or Value of Soil-Related Ecological Services

Author	Year Published	Location	Ecological Services Value	Willingness-to-Pay ($US)	Description of Values
Clark	1985	US	soil erosion damage (in-stream)	4,100 million	National value
Clark	1985	US	soil erosion damage (off stream)	1,900 million	National value
Hansen	2007	North East	CRP - benefits of conservation practices	8.32/1.27	Per ton water erosion/per ton wind erosion

Author	Year Published	Location	Ecological Services Value	Willingness-to-Pay ($US)	Description of Values
Hansen	2007	Appalachia	CRP - benefits of conservation practices	2.81/0.57	Per ton water erosion/per ton wind erosion
Hansen	2007	South East	CRP - benefits of conservation practices	2.89/0.41	Per ton water erosion/per ton wind erosion
Hansen	2007	Lake States	CRP - benefits of conservation practices	5.48/1.21	Per ton water erosion/per ton wind erosion
Hansen	2007	Corn Belt	CRP - benefits of conservation practices	2.60/1.01	Per ton water erosion/per ton wind erosion
Hansen	2007	Delta States	CRP - benefits of conservation practices	2.91/0.43	Per ton water erosion/per ton wind erosion
Hansen	2007	Southern Plains	CRP - benefits of conservation practices	2.71/0.74	Per ton water erosion/per ton wind erosion
Hansen	2007	Northern Plains	CRP - benefits of conservation practices	0.91/1.05	Per ton water erosion/per ton wind erosion
Hansen	2007	Mountain	CRP - benefits of conservation practices	2.10/0.86	Per ton water erosion/per ton wind erosion
Hansen	2007	Pacific	CRP - benefits of conservation practices	2.29/1.54	Per ton water erosion/per ton wind erosion
Huszar[1]	1989	New Mexico	wind erosion costs – on-site avoidance costs	10 million	Per year
Huszar[2]	1989	New Mexico	wind erosion costs – off-site avoidance costs	458 million	Per year
Huszar[2]	1989	New Mexico	wind erosion costs – off-site avoidance costs	360	Per person
Huszar[3]	1989	All Western States	wind erosion costs – off-site	3.76-12.08 billion	Per year
Huszar[4]	1989	US	water erosion costs – off-site	3.2-13 billion	Per year
Sullivan et al.	2004	North East	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	44	Per acre
Sullivan et al.	2004	Appalachia	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	36	Per acre

Author	Year Published	Location	Ecological Services Value	Willingness-to-Pay ($US)	Description of Values
Sullivan et al.	2004	South East	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	17	Per acre
Sullivan et al.	2004	Lake States	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	20	Per acre
Sullivan et al.	2004	Corn Belt	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	37	Per acre
Sullivan et al.	2004	Delta States	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	37	Per acre
Sullivan et al.	2004	Southern Plains	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	14	Per acre
Sullivan et al.	2004	Northern Plains	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	5	Per acre
Sullivan et al.	2004	Mountain	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	6	Per acre
Sullivan et al.	2004	Pacific	CRP-annual benefits from reduction in soil erosion (on-site + off-site)	9	Per acre
Williams, Tanaka, & Herbel	1993	Northern Great Plains	Aversion to soil erosion	4.90-5.20	Per acre for the 2.5-5 inch level of topsoil

[1] from Davis, R. and G.D. Condra. 1985. The On-Site Costs of Wind Erosion in New Mexico. Final Report to Soil Conservation Services. Albuquerque, New Mexico: U.S. Department of Agriculture.
[2] from Huszar, P., and S. L. Piper. 1986. Estimating the Off-Site Costs of Wind Erosion in New Mexico. Journal of Soil and Water Conservation 41 (6):414-16.
[3] from Piper, S.L. 1989. Measuring the Particulate Pollution Damage from Wind Erosion in the Western United States. Journal of Soil and Water Conservation 44 (1):70-75
[4] from Clark, E. H., J.A. Haverkamp, and W. Chapman. 1985. Eroding Soils: The Off-Farm Impacts. Washington, D.C. The Conservation Foundation

Table A1-6 lists the studies that provide WTP and benefits valuations for wetlands throughout the United States. Costanza et al (1997) indicates that wetlands have a value of approximately $4,879 per ha ($1,975 per ac), while Ingraham and Foster (2008) indicate that wetlands within the U.S. National Wildlife Refuge System provides value of $8,800 per acre per year. Blomquist and Whitehead (1998) indicated that respondents were willing to pay a one-time payment for

wetland preservation depending upon type of wetland between $2 to $11 rather than surface coal mining of the area in Western Kentucky. Nunes and van Den Bergh (2001) citing others indicated a WTP between $96 to $184 for a one-time payment into a program that would enhance wetlands and habitat. Jenkins, Murray, Kramer, and Faulkner (2010) indicated that wetland preservation in aggregate in the Mississippi Alluvial Valley was worth approximately $1,435 - $1,486 per ha per year. Woodward and Wui (2001) indicated that wetlands provide numerous functions and providing a value per single service ranging from $3 per acre for amenity values to $417 per acre for water quality values.

Table A1-6: Willingness-to-Pay for or Value of Wetland Ecological Services

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
Blomquist & Whitehead	1998	Western Kentucky	wetland preservation - flatwater marshes, persistent emergent wetland	1.69	One-time payment into a preservation fund for purchase of wetlands rather than surface coal mining
Blomquist & Whitehead	1998	Western Kentucky	wetland preservation - temporarily flooded wetland	4.69	One-time payment into a preservation fund for purchase of wetlands rather than surface coal mining
Blomquist & Whitehead	1998	Western Kentucky	wetland preservation - seasonally flooded wetland	3.68	One-time payment into a preservation fund for purchase of wetlands rather than surface coal mining
Blomquist & Whitehead	1998	Western Kentucky	wetland preservation - swamp, permanently flooded bottomland hardwood forests	11.21	One-time payment into a preservation fund for purchase of wetlands rather than surface coal mining
Costanza, et al.	1997	Global	value of natural capital - wetlands	4,879	Per hectare per year
Costanza, Farber, & Maxwell	1989	Louisiana	wetland preservation	2,429-6,400	Per acre (8% discount rate)
Costanza, Farber, & Maxwell	1989	Louisiana	wetland preservation	8,977-17,000	Per acre (5% discount rate)
Ingraham & Foster	2008	US National Wildlife Refuge System	wilderness area protection	8,800	Per acre per year
Jenkins, Murray, Kramer, & Faulkner	2010	Mississippi Alluvial Valley	wetland preservation – GHG mitigation	171-222	Per hectare per year
Jenkins, Murray, Kramer, & Faulkner	2010	Mississippi Alluvial Valley	wetland preservation – N mitigation	1,248	Per hectare per year

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
Jenkins, Murray, Kramer, & Faulkner	2010	Mississippi Alluvial Valley	wetland preservation – waterfowl recreation	16	Per hectare per year
Jenkins, Murray, Kramer, & Faulkner	2010	Mississippi Alluvial Valley	wetland preservation – aggregate	1,435-1,486	Per hectare per year
Milon & Scrogin	2006	Everglades	wetland restoration	29.33 - 59.26	Full restoration values per household
Nunes & van den Bergh[1]	2001	California	enhancing wetlands & habitat	96-184	One-time payment for a single program
Woodward & Wui	2001	US	wetland services – flood	393	Per acre
Woodward & Wui	2001	US	wetland services – quality	417	Per acre
Woodward & Wui	2001	US	wetland services – quantity	127	Per acre
Woodward & Wui	2001	US	wetland services – recreational fishing	357	Per acre
Woodward & Wui	2001	US	wetland services – commercial fishing	778	Per acre
Woodward & Wui	2001	US	wetland services – bird hunting	70	Per acre
Woodward & Wui	2001	US	wetland services – bird watching	1,212	Per acre
Woodward & Wui	2001	US	wetland services – amenity	3	Per acre
Woodward & Wui	2001	US	wetland services – habitat	306	Per acre
Woodward & Wui	2001	US	wetland services - storm	237	Per acre

[1] from Hoehn, J.P., and J.B. Loomis. 1993 Substitution effects in the valuation of multiple environmental programs. Journal of Environmental Economics and Management 25 (1):56-75

Tables A1-7 and A1-8 lists values associated with wilderness-related ecological services and open lands. Costanza et al. (1997) estimate that rangeland provide natural capital of $906 per ha ($367 per acre). Ingraham and Foster (2008) indicate that within the U.S. National Wildlife Refuge System shrublands provide a value of $550 per acre, while grassland provides $51.40 per acre. Overall, the U.S. National Wildlife Refuge System provides a combined value of $2,400 per acre. Banzhaf, Burtraw, Evan, and Krupnick (2006) indicate that natural resource improvement within the Adirondacks had a value between $48 and $159 per household per year for 10 years depending upon the discount rate. Loomis, Traynor, and Brown (1999) found that households in Loveland, Colorado, had a WTP $106 per household for ten years for the preservation of both recreation and open lands. Ellington, Seidle, and Mucklow (2006) found that tourist would reduce their spending per trip by $230 to Routt County, Colorado if the ranchland within the county was developed. Similarly, Magnan, Seidle, Mucklow, and Alpe (2005) found a per resident WTP of $220 to preserve ranchland in Routt County, Colorado.

Table A1-7: Willingness-to-Pay for or Value of Wilderness-Related Ecological Services

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
Banzhaf[1]	2010	Boulder, CO	scenic views & open space	294	One-time payment
Banzhaf, Burtraw, Evan, & Krupnick	2006	New York	natural resource improvements Adirondacks	48-107	Per household per year for 10 years (3% discount rate)
Banzhaf, Burtraw, Evan, & Krupnick	2006	New York	natural resource improvements Adirondacks	54-159	Per household per year for 10 years (5% discount rate)
Banzhaf, Burtraw, Evan, & Krupnick	2006	New York	natural resource improvements Adirondacks	336 million - 1.1 billion	Total public benefits
Boyle	1990	Illinois Beach State Nature Reserve	protection	$37-41 (linear model) $96-111 (log model)	
Costanza, et al.	1997	Global	value of natural capital – rangeland	906	Per hectare per year
Ingraham & Foster	2008	US National Wildlife Refuge System	wilderness area protection - open land	290	Per acre per year
Ingraham & Foster	2008	US National Wildlife Refuge System	wilderness area protection- shrubland	550	Per acre per year
Ingraham & Foster	2008	US National Wildlife Refuge System	wilderness area protection – grassland	51.40	Per acre per year
Ingraham & Foster	2008	US National Wildlife Refuge System	wilderness area protection – total value	2,400	Per acre per year
Loomis	2005	US National forests & other public lands	recreational activities on national forests & other public lands	47.64	Per person per day consumer surplus
Loomis, Traynor, & Brown	1999	Loveland, CO	preservation of open lands – recreation lands	108	Per household per year for 10 years
Loomis, Traynor, & Brown	1999	Loveland, CO	preservation of open lands – nature lands	116	Per household per year for 10 years
Loomis, Traynor, & Brown	1999	Loveland, CO	preservation of open lands – both types	106	Per household per year for 10 years
Nunes & van den Bergh[2]	2001	CO, ID, MT, WY	protecting wilderness areas	29-66	

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
Walsh, Loomis, & Gillman	1984	Colorado	wilderness area protection	32	

[1] Breffle, W.S., E.R. Morey, R.D. Rowe, and D.M. Waldman. 2006. Combining stated choice and stated frequency data with observed data to value NRDA compensable damages: Green Bay, PCBs, and fish consumption advisories. In: Alberini, A. and J.R. Kahn (eds.), Handbook on Contingent Valuation. Elgar, Cheltenham, UK.

[2] Diamond, P.A., J.A. Hausman, G.L., Leonard, and M.A. Denning. 1993. Does CV measure preferences? Experimental evidence, In.: Hausman, J.A. (ed.) Contingent valuation: A critical assessment, contributions to economic analysis, Chapter II, North-Holland, New York.

Table A1-8: Willingness-to-Pay for of Value of Open Lands and Rangelands Ecological Services

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
Berrens, Brookshire, Ganderton, & McKee	1998	New Mexico	grazing on federal lands – rangeland	21.68 to -71.01	Value to maintain grazing
Bowman, Thompson, & Colletti	2009	Cedar Rapids, IA	subdivision open space	241	Per acre increase in property values
Bowman, Thompson, & Colletti	2009	Cedar Rapids, IA	conservation features contribution to housing prices	882/8688	Contribution of open space per house
Bowman, Thompson, & Colletti	2009	Cedar Rapids, IA	WTP for additional open space	4,343	Average for additional open space
Cho, Newman, & Bowker	2005	Macon County, NC	farmland conservation easement	10.97-17.39	Per household at the county level
Cho, Newman, & Bowker	2005	Macon County, NC	farmland conservation easement	16.30-21.79	Per household with no on-respondents
Ellingson, Seidle, & Mucklow	2006	Routt County, CO	preservation of ranchland	230	Lost per person per trip if all ranchland in county was converted
Magnan, Seidl, Mucklow, & Alpe	2005	Routt County, CO	preservation of ranchland	220	Per resident
Rosenberger & Walsh	1997	Routt County, CO	protection of ranchland	141.13	Per household per year

Table A1-9 provides values associated with per person per day of wildlife related recreation. The U.S. Fish and Wildlife Service 2006 National Survey of Hunting, Fishing, and Wildlife Related Activities found that a large population of the U.S. enjoys outdoor related activities. Values for specific species ranged from $63 per person per day for walleye for in-state residents to $155 per person per day for moose in Alaska. For out-of-state residents, values ranged from $95 per person per day for elk hunting to $134 per person per day for trout fishing. Wildlife

watching activities ranged from $57 per person per day for residents and $122 per person per day for out-of-state.

Table A1-9: Willingness-to-Pay for or Value of Wildlife and Wildlife-Related Recreation Ecological Services

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
Bagsund, Houdur, & Leistritz	2004	North Dakota	CRP - benefits of conservation practices – wildlife recreation hunting	9.45	Per CRP acre
Feather, Hellerstein, & Hansen	1999	Pacific/Mountain	CRP-freshwater based recreation	0.21	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	Northern Plains	CRP-freshwater based recreation	0.28	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	Southern Plains	CRP-freshwater based recreation	0.29	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	South Eastern	CRP-freshwater based recreation	2.93	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	North Eastern	CRP-freshwater based recreation	2.45	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	total value	CRP-freshwater based recreation	1.07	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	Pacific/Mountain	CRP-pheasant hunting	0.33	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	Northern Plains	CRP-pheasant hunting	3.00	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	North Eastern	CRP-pheasant hunting	6.24	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	total value	CRP-pheasant hunting	2.36	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	Pacific/Mountain	CRP-based wildlife viewing	-4.27	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	Northern Plains	CRP-based wildlife viewing	3.01	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	Southern Plains	CRP-based wildlife viewing	12.14	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	South Eastern	CRP-based wildlife viewing	1.33	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	North Eastern	CRP-based wildlife viewing	35.44	Per CRP acre per year
Feather, Hellerstein, & Hansen	1999	total value	CRP-based wildlife viewing	10.02	Per CRP acre per year
Hansen	2007	North East	CRP - benefits of conservation practices	47.50	Per CRP acre per year

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
Hansen	2007	Appalachia, South East, Delta States combined	CRP - benefits of conservation practices	42.39	Per CRP acre per year
Hansen	2007	Lakes States & Corn Belt combined	CRP - benefits of conservation practices	55.43	Per CRP acre per year
Hansen	2007	Southern Plains	CRP - benefits of conservation practices	26.36	Per CRP acre per year
Hansen	2007	Northern Plains	CRP - benefits of conservation practices	7.79	Per CRP acre per year
Hansen	2007	Mountain & Pacific combined	CRP - benefits of conservation practices	0.58	Per CRP acre per year
Hansen	2007	Montana	CRP - benefits of conservation practices	1.77	Per CRP acre per year
Sullivan et al.	2004	North East	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	45	Per CRP acre per year
Sullivan et al.	2004	Appalachia	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	41	Per CRP acre per year
Sullivan et al.	2004	South East	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	40	Per CRP acre per year
Sullivan et al.	2004	Lake States	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	52	Per CRP acre per year
Sullivan et al.	2004	Corn Belt	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	52	Per CRP acre per year
Sullivan et al.	2004	Delta States	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	40	Per CRP acre per year
Sullivan et al.	2004	Southern Plains	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	27	Per CRP acre per year
Sullivan et al.	2004	Northern Plains	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	7	Per CRP acre per year
Sullivan et al.	2004	Mountain	CRP-total wildlife benefits per acre -	1	Per CRP acre per year

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
			wildlife viewing, pheasant hunting		
Sullivan et al.	2004	Pacific	CRP-total wildlife benefits per acre - wildlife viewing, pheasant hunting	1	Per CRP acre per year
USFWS	2009	US	wildlife related recreation – deer hunting	78	Mean per person per day of state resident
USFWS	2009	US	wildlife related recreation – deer hunting	98	Mean per person per day out of state resident
USFWS	2009	US	wildlife related recreation – elk hunting	81	Mean per person per day of state resident
USFWS	2009	US	wildlife related recreation – elk hunting	95	Mean per person per day out of state resident
USFWS	2009	US	wildlife related recreation – moose	155	Mean per person per day of state resident
USFWS	2009	US	wildlife related recreation – bass fishing	68	Mean per person per day of state resident
USFWS	2009	US	wildlife related recreation – bass fishing	116	Mean per person per day out of state resident
USFWS	2009	US	wildlife related recreation – trout fishing	56	Mean per person per day of state resident
USFWS	2009	US	wildlife related recreation – trout fishing	134	Mean per person per day out of state resident
USFWS	2009	US	wildlife related recreation – walleye fishing	63	Mean per person per day of state resident
USFWS	2009	US	wildlife related recreation – walleye	110	Mean per person per day

Author	Year Published	Location	Ecological Services	Willingness-to-Pay ($US)	Description of Values
			fishing		out of state resident
USFWS	2009	US	wildlife related recreation – wildlife watching	57	Mean per person per day of state resident
USFWS	2009	US	wildlife related recreation – wildlife watching	122	Mean per person per day out of state resident

Table A1-10 provides estimated costs for reclamation and restoration activities for forestry and herbaceous species. Baker (2008) provides per state estimates for coal mine reclamation within Appalachia with forestry restoration being slightly less expenses with a range from $1,459 to $1,899. For herbaceous restoration costs ranged from $1,610 to $2,210 (Baker 2008). Bonham and Stephenson (2004) estimated an average per linear foot cost of stream restoration in Southern Appalachia at $59.20 per linear foot; however, they found that economies of scale existed. The Environmental Law Institute, from a survey of U.S. Army Corps of Engineers district regulatory programs associated with Section 404 of the CWA, found an average stream mitigation cost of $240 per linear foot.

Table A1-10: Estimated Costs of Reclamation and Restoration Activities for Forestry and Herbaceous

Author	Year Published	Location	Ecological Services	Estimated Cost ($US)	Description of Values
Baker	2008	Appalachian coal mine	forestry reclamation - Kentucky	1,573.65	Per acre
Baker	2008	Appalachian coal mine	forestry reclamation – Maryland	1,543.21	Per acre
Baker	2008	Appalachian coal mine	forestry reclamation – Ohio	1,899.20	Per acre
Baker	2008	Appalachian coal mine	forestry reclamation – Pennsylvania	1,678.68	Per acre
Baker	2008	Appalachian coal mine	forestry reclamation-Tennessee	1,459.64	Per acre
Baker	2008	Appalachian coal mine	forestry reclamation – Virginia	1,514.86	Per acre
Baker	2008	Appalachian coal mine	forestry reclamation – West Virginia	1,859.51	Per acre
Baker	2008	Appalachian coal mine	hayland/pastureland restoration – Kentucky	1,797.87	Per acre

Author	Year Published	Location	Ecological Services	Estimated Cost ($US)	Description of Values
Baker	2008	Appalachian coal mine	hayland/pastureland restoration – Maryland	1,711.43	Per acre
Baker	2008	Appalachian coal mine	hayland/pastureland restoration – Ohio	1,841.43	Per acre
Baker	2008	Appalachian coal mine	hayland/pastureland restoration – Pennsylvania	1,993.13	Per acre
Baker	2008	Appalachian coal mine	hayland/pastureland restoration – Tennessee	1,610.72	Per acre
Baker	2008	Appalachian coal mine	hayland/pastureland restoration – Virginia	1,654.96	Per acre
Baker	2008	Appalachian coal mine	hayland/pastureland restoration – West Virginia	2,210.25	Per acre
Bonham & Stephenson	2004	Southern Appalachia region	stream mitigation	59.20	Average per linear foot
Bonham & Stephenson	2004	Southern Appalachia region	stream mitigation - small projects (<3,000 lf)	118.96	Per acre
Bonham & Stephenson	2004	Southern Appalachia region	stream mitigation - medium projects (3,001 - 10,000 lf)	92.74	Per acre
Bonham & Stephenson	2004	Southern Appalachia region	stream mitigation - large projects (>10,000 lf)	65.22	Per acre
Environmental Law Institute	2007	US	stream mitigation	240	Average per linear foot
Holmes, Bergstrom, Huszar, Kask, & Orr	2004	Little Tennessee River	riparian restoration activities	0.98	Per linear foot of riparian buffer with no fencing
Holmes, Bergstrom, Huszar, Kask, & Orr	2004	Little Tennessee River	riparian restoration activities	3.13	Per linear foot of riparian buffer with fencing
Holmes, Bergstrom, Huszar, Kask, & Orr	2004	Little Tennessee River	riparian restoration activities	15.50	Per linear foot of revetment construction with on-site trees
Holmes, Bergstrom, Huszar, Kask, & Orr	2004	Little Tennessee River	riparian restoration activities	20.33	Per linear foot of revetment with no trees on site

Table A1-11 provides a brief review of a case study of the WTP for clean at the Eagle Mine in Eagle County, Colorado.

Table A1-11: Coal Mine Restoration Costs

Author	Year Published	Location	Ecological Services	Mean Willingness-to-Pay ($US)	Description of Values
Damigos	2006	Eagle County, CO	Restoration of Eagle Mine - clean-up and protection of the Eagle River	70.00	Eagle County Survey
Damigos	2006	Eagle County, CO	Restoration of Eagle Mine - clean-up of statewide hazardous wastes	178.61	Statewide survey subsample Eagle County residents
Damigos	2006	Eagle County, CO	Restoration of Eagle Mine - clean-up of statewide hazardous wastes	179.32	Statewide survey sample, remaining residents
Damigos	2006	Eagle County, CO	Restoration of Eagle Mine - Eagle Mine clean-up	73.12	Statewide survey subsample Eagle County residents
Damigos	2006	Eagle County, CO	Restoration of Eagle Mine - Eagle Mine clean-up	11.62	Statewide survey sample

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APPENDIX 2

MINING COSTS

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APPENDIX 3

OSM COST BURDEN ANALYSIS

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APPENDIX 4

COAL PRODUCTION SHIFT ANALYSIS

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APPENDIX 5

BASELINE IMPLAN INPUT-OUTPUT ANALYSIS

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APPENDIX 6

STATE COAL INDUSTRY PROFILE

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STATE COAL INDUSTRY PROFILES

Introduction

This appendix summarizes some of the major findings of an analysis of the coal-mining industry in each of the 25 coal-producing states. Detailed profile information is in Appendix H. The information comes primarily from the EIA State Energy Profiles, interviews with state coal regulatory agencies, and other public industry and economic data sources.

Appalachian Coal-producing Region

Alabama Profile.

Alabama is rich in energy resources. The state has considerable conventional and unconventional natural gas reserves, substantial deposits of coal, and numerous rivers capable of hydroelectric generation. With a strong manufacturing base in paper products, chemicals, and textiles, Alabama's industrial sector leads state energy consumption, accounting for nearly one-half of total energy use.

Additionally, Alabama ranks among the top 10 states in electricity generation. Coal is the dominant fuel for electric power generation, typically accounting for more than one-half of the electricity produced within the state. Alabama produces large amounts of coal in the northern part of the state. Industrial plants and coke plants consume a larger share of the state's output than in most other states. Additional coal, largely used for electricity generation, is shipped in from other states, primarily Wyoming, Kentucky, and West Virginia. This imported coal accounts for nearly one-half of the state's demand.[1]

There are 21 coal mines in Alabama with production greater than 200,000 tons per year. Alabama's largest coal seams run through Tuscaloosa, Fayette, Jefferson, Walker, and Shelby Counties. Approximately two-thirds of Alabama's coal is high-grade metallurgical coal and is sold (mostly exported) for steel making. The remaining one-third is mostly mined from surface mines and sold to coal-fired power plants. The metallurgical coal has very low sulfur content, a high heat value, and is known as "Blue Creek" coal.[1]

Two of the deepest underground coal mines in the United States are located near Brookwood, Alabama, and are operated by Jim Walter Resources. Jim Walter Resources is Alabama's largest coal-mining company, with 1,300 employees. The company's mines are the southernmost mines in the Appalachian Region.[1]

Alabama had a 2008 consumption of 35,845,000 short tons by the electric generation industry, with an additional 1,723,000 used for coke production. Alabama had to import nearly 17,000,000 tons of coal from other states.

Tennessee Profile.

Tennessee also has minor coal reserves in the Appalachian Basin in the eastern part of the state. Tennessee ranks among the top 20 states in terms of both absolute and per capita energy consumption. The industrial sector leads state energy demand. With 2.80 million tons of coal

mined in 2006, Tennessee is one of the lesser coal-mining states, constituting only 0.2 percent of U.S. coal production. Coal mines employed 643 people in 2006, all of whom were non-union.

Tennessee had 63 coal-fired generating stations in 2005, with a total of 10,290 MW of capacity; this represents 44.8 percent of the state's electric-generating capacity, and makes Tennessee the 14th largest coal energy-producing state. [1]

Coal-fired power plants typically generate more than one-half of the electricity produced in Tennessee; nuclear and hydroelectric power supplies most of the remainder. Tennessee's coal production is minor, and the state's coal-fired power plants rely on coal delivered primarily by railroad and river barge from other states. Tennessee receives most of its coal from Wyoming, Illinois, Colorado, Kentucky, West Virginia, and Virginia. Tennessee is a major nuclear power producer, with two nuclear power plants in the southeastern part of the state near Chattanooga. Tennessee electricity consumption is high, and the state leads the nation in per capita residential electricity consumption. More than one-half of Tennessee households use electricity as their primary source of energy for home heating.[1]

There were 89 establishments for the mining (except oil and gas) sector in Tennessee in 2008, with a total of 1,199 employees.

The average weekly wage for the mining (except oil and gas) sector in Tennessee in 2008 was $804. This would be equivalent to $20.10 per hour or $41,807 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Tennessee is projected to grow by -6.5 percent between 2008 and 2018, which is slower than the 12.0 percent growth rate for all industries in the state. This amounts to 79 lost jobs over the period, or approximately 8 jobs lost per year.

Kentucky Profile.

Kentucky is the third largest coal-producing state, after Wyoming and West Virginia. It accounts for approximately one-tenth of total U.S. coal production and nearly one-fourth of U.S. coal production east of the Mississippi River. Although all Kentucky coal is bituminous, its sulfur content varies across the state. Coal produced in the Central Appalachian Basin is low in sulfur, while coal produced in the Illinois Basin is high in sulfur. Nearly one-third of all the coal mines in the nation are found in Kentucky, more than in any other state. Kentucky has both surface and underground coal mines. Large volumes of coal move into and out of Kentucky by railcar and river barge. Kentucky delivers approximately three fourths of state coal production to more than 24 states, most of which are on the East Coast and in the Midwest. Nearly 95 percent of the coal used in Kentucky is burned for electricity generation, and most of the remainder is used in industrial and coke plants.

Kentucky has major coal deposits in the eastern Central Appalachian Basin and in the western Illinois Basin. Those basins also hold minor reserves of oil and gas. The Tennessee and Cumberland Rivers in the Ohio River Basin provide hydroelectric power potential. Kentucky's per capita energy consumption is among the highest in the nation, and the industrial sector leads state energy demand. The state is a leader in the energy-intensive aluminum industry. [1]

Coal-fired power plants typically account for more than nine-tenths of the electricity produced in Kentucky, making it one of the most coal-dependent states in the nation. The remaining electricity generation within the state is mostly provided by petroleum-fired and hydroelectric power plants. Kentucky's per capita consumption of residential electricity is among the highest in the United States. More than two-fifths of Kentucky households use electricity as their primary energy source for home heating.[1]

There were 430 establishments for the mining (except oil and gas) sector in Kentucky in 2008, with a total of 19,293 employees.

The average weekly wage for the mining (except oil and gas) sector in Kentucky in 2008 was $1,224. This would be equivalent to $30.60 per hour or $63,644 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Kentucky is projected to grow by 6.8 percent from 2008 to 2018, which is consistent with the 7.5 percent growth rate for all industries in the state. This amounts to 1,305 new jobs over the period, or approximately 130 jobs created per year.

Maryland Profile.

Maryland coal mines produced 5.1 million tons of coal in 2006 (0.4 percent of the U.S. total), making Maryland the 17th largest coal-producing state in the country. Maryland employed 473 coal miners in 2006, of which none were union members.

Maryland had 18 coal-fired generating stations in 2005, with 5,236 MW of capacity, representing 39.1 percent of the state's total electric-generating capacity; Maryland ranks 25th of the 50 states in terms of coal-fired electric-generating capacity.[1]

Maryland is a minor producer of coal, with supplies in the West; most of the state's coal-fired power plants burn coal shipped from West Virginia and Pennsylvania. The Conowingo hydroelectric plant on the Susquehanna River, one of Maryland's largest generation facilities, provides almost all of the state's hydroelectricity. More than one-third of Maryland households use electricity as their main source of energy for home heating.

In April 2008, Maryland accelerated its existing renewable portfolio standard to require that renewable energy sources generate 20 percent of the state's electricity by 2022, with 2 percent of that from solar sources. [1]

There were 63 establishments for the mining (except oil and gas) sector in Maryland in 2008, with a total of 1,289 employees. The average weekly wage for the mining (except oil and gas) sector in Maryland for the fourth quarter of 2009 was $1,149. This would be equivalent to $28.75 per hour or $59,748 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Maryland is projected to grow by -1.7 percent from 2008 to 2018, which is slower than the 9.1 percent growth rate for all industries in the state. This decline projects that there will be 20 jobs lost over the period, or approximately 2 jobs lost per year.

Ohio Profile.

Ohio's coal mines began exporting coal by barge to other states in 1827. In the subsequent decades, railroads and canals opened up new markets in other states, and by 1875 the state's annual coal production totaled 5 million tons. By 1889, Ohio was producing 10 million tons of coal each year and was the third largest coal-producing state in the country. In 1918, the state's coal production peaked at 46 million tons; Ohio's coal industry declined in subsequent decades. The 1960s witnessed a dramatic revitalization of Ohio's coal industry, and production climbed from approximately 32 million tons in 1960 to 55.4 million tons in 1970. However, the passage of the CAA greatly affected Ohio's coal industry, which produces primarily higher-sulfur coal; production declined to 39.4 million tons in 1980, 30.4 million tons in 1992, and 22.7 million tons in 2006.

Ohio had 119 coal-fired generating stations in 2005, with 23,825 MW of capacity, representing 64.9 percent of the state's total electric-generating capacity and making Ohio the largest coal energy-producing state in the United States.[1]

Although Ohio is a moderate producer of coal, it is a substantial consumer. Ohio ranks fourth in the United States in coal consumption. Ohio's coal mines, concentrated in the Appalachian Basin in the eastern part of the state, typically supply less than one-third of the state's coal consumption. The remaining coal is brought in primarily by railcar and river barge from West Virginia, Wyoming, Kentucky, and Pennsylvania. Although large amounts of coal are used by industry, its primary use is for electricity generation and coal fuels close to nine-tenths of Ohio's total generation. Two nuclear plants located along Lake Erie supply most of the remainder of the state's generation.

Although it is one of the nation's top generators of electricity, Ohio is also among the major importers of electricity. Ohio's total electricity consumption is high mostly because of the state's energy-intensive industrial sector, which accounts for more than one-third of the state's electricity consumption. The residential sector consumes approximately one-fourth of the state's electricity, with nearly one-fifth of Ohio households relying on electricity as their primary source of energy for home heating. In August 2003, a transmission failure in Northeastern Ohio led to the largest blackout in North American history, affecting an estimated 50 million people in the northeastern United States and Canada. More than 500,000 Ohio homes and businesses lost power during the incident. [1]

Ohio established an alternative energy portfolio standard in 2008, mandating that at least 25 percent of all electricity sold in the state come from alternative energy resources by 2025. At least one-half of this electricity must be generated in Ohio itself. Renewable sources such as wind, solar, hydroelectric power, geothermal, and biomass must account for at least one-half of the standard, or 12.5 percent of electricity sold. The other one-half of the standard can be met through alternative energy resources such as third-generation nuclear power plants, fuel cells, energy-efficiency programs, and clean coal technology that can control CO_2emissions.

There were 326 establishments for the mining (except oil and gas) sector in Ohio in 2008, with a total of 5,834 employees. The average weekly wage for the mining (except oil and gas) sector in Ohio in 2008 was $1,044. This would be equivalent to $26.10 per hour or $54,311 per year, assuming an annual 40-hour work week. The mining (except oil and gas) sector in Ohio is projected to grow by -3.3 percent from 2006 to 2016, much slower than the 5.0 percent growth

rate for all industries in the state. This amounts to 200 lost jobs over the 10-year period, or approximately 20 jobs lost per year.

Pennsylvania Profile.

Pennsylvania is a major coal-producing state. Northeastern Pennsylvania's coal region holds the nation's largest remaining reserves of anthracite coal, a type of coal that burns cleanly with little soot. It is used primarily as a domestic fuel in either hand-fired stoves or automatic stoker furnaces. Although Pennsylvania supplies virtually all of the nation's anthracite, most of the state's coal production consists of bituminous coal mined in the western part of the state, where several of the nation's largest underground coal mines are located. Enlow Fork Mine is the largest underground coal mine in the United States. Pennsylvania sells approximately one-half of its coal output to other states throughout the East Coast and Midwest. The Appalachian Basin, which covers most of the state, holds substantial reserves of coal, as well as minor reserves of crude oil and natural gas. Pennsylvania is the fourth leading coal-producing state, mining 68 million tons last year. Almost 80 percent of this output came from 39 underground mines and the remainder from 377 surface-mining and reprocessing sites.

Large volumes of coal are moved both into and out of Pennsylvania, mostly by railcar, river barge, and truck. Pennsylvania transports close to one-half of its coal production to other states throughout the East Coast and Midwest. Pennsylvania coal demand is high, and it is one of the top coal-consuming states in the nation. Pennsylvania's coal dominates the state's power generation market, typically accounting for more than one-half of net electricity production. [1]

In addition, coal is by far the least expensive fossil fuel on a dollar-per-MMBtu basis for electric generation, averaging almost one-fourth the price of natural gas ($2/MMBtu versus $7/MMBtu).

There were 578 employer establishments for mining (except oil and gas) in Pennsylvania in 2008, with a total of 13,609 employees.

The average weekly wage for the mining (except oil and gas) sector in Pennsylvania in 2008 was $1,148. This would be equivalent to $28.70 per hour or $59,700 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Pennsylvania is projected to grow by 3.2 percent from 2009 to 2019, slower than the 5.7 percent growth rate for all industries in the state. This amounts to 440 new mining jobs over the period, or approximately 44 jobs created per year.

Virginia Profile.

Virginia accounts for nearly 10 percent of U.S. coal production east of the Mississippi River. Production takes place at surface and underground mines in the Central Appalachian Basin. Large volumes of coal move through Virginia by rail, including production from Kentucky and West Virginia. Virginia's coal is shipped to nearly one-half of the states in the nation; the primary recipients are Georgia and Tennessee. Most coal consumed in Virginia is used for electricity generation.

Coal-fired power plants typically account for nearly one-half of the state's electricity generation. Two nuclear power plants account for approximately one-third of the state's generation, and

natural gas- and petroleum-fired power plants account for much of the remainder. Close to one-half of households in Virginia use electricity as their primary energy source for home heating. Wood and wood waste provide Virginia with approximately 2.5 percent of its total electricity production, while other renewable sources, such as hydroelectric power, municipal solid waste, and landfill gas, contribute minimally. In April 2007, Virginia established a voluntary renewable portfolio goal that encourages utilities to generate 12 percent of base year 2007 sales from renewable sources by 2022.[1]

Coal-fired power plants produce approximately 47 percent of the electricity generated in Virginia. Virginia's average retail price of electricity is 6.86 cents per kW-h, the 12th lowest rate in the nation. Coal production is an important part of Virginia's economy, with an estimated 30 to 40 million tons produced each year. Virginia's coal mines are located in the Appalachian Mountains in the southwestern part of the state, predominantly in Buchanan, Dickenson, and Wise Counties. Relative to coal mined in other parts of the United States, Virginia coal has high energy content and low sulfur content, making it well suited to electricity generation.

Virginia coal is used to supply approximately one-half of the state's energy needs. The state also imports coal for power generation, mainly from Kentucky and West Virginia. Virginia-based Dominion recently began importing low-sulfur coal from Indonesia and Columbia. Virginia also exports coal to electric utilities in the southeastern states, and sells one-third to one-half of its in-state coal output for steel production, an industry that requires high-quality coal and tends to pay higher prices than electrical markets.[1]

There were 102 establishments for the mining (except oil and gas) subsector in 2008, with a total of 4,534 employees.

The average weekly wage for the mining (except oil and gas) subsector in the fourth quarter of 2009 was $1,539. This would be equivalent to $38.48 per hour or $80,038 per year, assuming an annual 40-hour work week.

The mining sector in Virginia is projected to grow by -9.3 percent from 2008 to 2018.This is a substantial decline compared to the 11.2 percent growth rate for all industries in the state. This amounts to 420 jobs lost over the 10-year period, or approximately 42 jobs lost per year.

Virginia has 217 million short tons of recoverable coal at existing mines, according to a September 2009 USEIA report. Virginia's estimated recoverable and demonstrated coal reserves are 2.3 billion.

West Virginia Profile.

West Virginia is the top coal-producing state east of the Mississippi River and the second largest coal-producing state in the nation. The coal output for West Virginia accounts for nearly one-third of U.S. production from Eastern states and more than 10 percent of total U.S. coal production. Although all West Virginia coal is bituminous, coal sulfur content varies, with low-sulfur coal from southern mines and high-sulfur coal from the northern part of the state. West Virginia is also the national leader in coal production from underground mines. Underground mines are responsible for more than one-half of the state's production totals. Large shipments of coal move in and out of West Virginia primarily by river barge and rail. West Virginia delivers coal to more than 25 states, mainly on the East Coast and in the eastern part of the Midwest.

More than 90 percent of the coal consumed in West Virginia is used for generating electricity, while the balance is utilized in industrial applications and coke plants. West Virginia is the leader, at 93 percent of its electricity generation coming from coal-fired plants. West Virginia is a high-electricity-production state, and although more than one-third of West Virginia households use electricity as their primary source for home heating, consumption is still relatively low. West Virginia ranks second in the nation after Pennsylvania in net interstate electricity exports. West Virginia does not have a renewable portfolio standard. However, the State has adopted a net-metering policy to credit customers' utility bills for electricity they provide to the grid from renewable sources. [1]

In recent decades, the West Virginia coal-mining industry has been trending downward. In 1997, production was 181 million tons, and the most recent reports show 2009 at 144 million. One positive factor regarding West Virginia coal is that it has higher energy content than Western coal, by approximately 50 percent. When the 1970 CAA was passed, placing caps on sulfur dioxide emissions, Wyoming coal, with sulfur content averaging approximately 0.35 percent, became the preferred source of fuel for coal-fired electricity generation plants over Appalachian coal, which has much higher sulfur dioxide content.[1]

West Virginia has more estimated recoverable coal reserves at producing mines than any other state, except Wyoming. Coal deposits are located in the Central and Northern Appalachian Basins, which underlie all but the eastern edge of the state. Those basins also hold smaller natural gas and crude oil reserves. Several rivers flowing from the Appalachian Mountains offer hydroelectric power resources. The industrial sector dominates West Virginia energy consumption, and per capita energy use is high.[1]

There were 354 establishments for the mining (except oil and gas) subsector in 2008, with a total of 21,370 employees.

The average weekly wage for the mining (except oil and gas) subsector in 2008 was $1,409. This would be equivalent to $35.23 per hour or $73,275 per year, assuming an annual 40-hour work week.

The mining sector in West Virginia is projected to grow by -1.1 percent from 2008 to 2018; this is a slight decline and well below the 6 percent growth rate for all industries in the state. This amounts to 216 jobs lost over the 10-year period, or approximately 22 jobs lost per year.

Interior Region: State Coal Profiles.

Arkansas Profile.

Arkansas has moderate energy resources. Substantial natural gas reserves are found in the Arkoma Basin in Western Arkansas and in the Gulf Coastal Plain in the South. Smaller oil reserves and coal deposits are also found in those regions. Several river basins, including the Lower Arkansas River, offer hydroelectric power potential. Areas of the state are also suitable for wind, wood, and wood waste power generation. Per capita energy use is high partly because of an energy-intensive industrial sector, which leads state energy consumption.

Coal and nuclear power are the dominant energy sources used for electricity generation in Arkansas, although natural gas and hydroelectric power are also important. Coal-fired power

plants account for approximately one-half of the electricity produced within the state, and these plants rely entirely on coal deliveries from Wyoming.

Although coal production in Arkansas is relatively small in terms of production and output, the state still consumed more than 15 million short tons of coal for electrical power in 2004. In 2008, the state produced and distributed approximately 13,000 short tons of coal, which ranked it 26th in the nation in coal production according to NMA. Although most of the most accessible coal has already been mined, Arkansas still has abundant coal deposits. There are an estimated 1 billion tons of bituminous coal still present in the Arkansas River Valley, and much of this coal has relatively low sulfur content. There are also approximately 9 billion tons of lignite coal reserves in the eastern and southern parts of the state. [1]

There were 111 mining (except oil and gas) establishments in Arkansas in the fourth quarter of 2008, with a total of 2,141 employees.

The average weekly wage for the mining (except oil and gas) sector in Arkansas for the fourth quarter of 2008 was $898. This would be equivalent to $22.45 per hour or $46,696 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Arkansas is projected to grow by -5.1 percent from 2006 to 2016, compared to a projected 15.1 percent growth rate for all industries in the state. This projected rate would result in the loss of 51 jobs over the 10-year period, or approximately 5 jobs lost per year.

Illinois Profile.

Coal deposits, as well as smaller deposits of oil and gas, are concentrated in the Illinois Basin, which underlies much of the southern and eastern parts of the state. In addition to fossil fuel reserves, Illinois has high ethanol potential because its production of corn, which is the primary feedstock for U.S. ethanol production, ranks second in the country behind Iowa. Illinois is one of the nation's top energy-consuming states, primarily because of its large population and high demand from the industrial sector, which includes the energy-intensive aluminum, chemicals, metal-casting, petroleum-refining, and steel industries.

Although the state's estimated recoverable coal reserves represent more than one-tenth of the U.S. total, only a small fraction of those reserves is located at producing mines. Illinois delivers more than one-half of its coal output to other states, including Indiana, Tennessee, Florida, and Missouri. Illinois also receives coal from other states, particularly Wyoming, and uses that coal to generate electricity.[1]

Illinois is one of the top electricity-generating states in the nation and a leading net exporter of electricity to other states. Coal- and nuclear-powered generation plants account for more than 95 percent of the electricity generated in Illinois. Just more than one-tenth of Illinois households use electricity as their primary energy source for home heating.

Some of the issues facing the coal industry in Illinois include the following:

- In August 2007, Illinois adopted a statewide renewable energy standard requiring the state's utilities to produce at least 25 percent of their power from renewable

sources by 2025. Seventy-five percent of the electricity used to meet the renewable standard must come from wind; other eligible sources include solar, biomass, and existing hydroelectric power. The law also includes an energy efficiency portfolio standard that requires utilities to implement cost-effective energy efficiency measures to reduce electricity usage by 2 percent of demand by 2015.[1]

- In 2007, Illinois had 3,001 coal miners at an average age of 52. Training new miners to replace experienced miners as they retire is another chief concern of the state. [1]
- The price volatility of commodities used in mining impacts the cost of operations. Rising costs are occurring for diesel fuel on surface operations; large truck-to-barge shippers; underground haulage equipment; petroleum-based products such as lubricants, oils, and the resin used in roof bolting; and the chemical used in preparation plant thickeners, conveyor belting, and rubber tires.[1]
- The cost and availability of steel and metal have surpassed almost every other supply needed for mining. Everything used in the industry has price changes weekly, with either fuel surcharges or steel surcharges.[1]

Indiana Profile.

Indiana has moderate coal reserves in the Illinois Basin in the southwestern part of the state, but relatively few other energy resources. As one of the nation's top corn-producing states, it has major ethanol production potential. Driven by an energy-intensive industrial sector, Indiana's total and per capita energy consumption is high. Energy-intensive industries in the state include aluminum, chemicals, glass, metal casting, and steel.

Indiana is a moderate producer of coal. Relatively small coal mines are concentrated in the Illinois Basin Region of Southwestern Indiana. Although their combined output typically amounts to approximately 3 percent of total U.S. coal production, these mines supply only approximately one-half of state demand. The remainder is brought in by railcar and river barge primarily from Wyoming, West Virginia, and Illinois. Coal is primarily used in Indiana for electricity generation, although large amounts are also used by the industrial sector. Indiana is a leader in the use of coal in coke plants, which serve the state's steel industry. [1]

There were 257 establishments for the mining (except oil and gas) sector in Indiana in for 2008, with a total of 6,002 employees.

The average weekly wage for the mining (except oil and gas) sector in Indiana for 2008 was $1,130. This would be equivalent to $28.25 per hour or $58,760 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Indiana is projected to grow by 4.6 percent from 2006 to 2016, which is slightly slower than the 7.7 percent growth rate for all industries in the state. This amounts to 304 new jobs over the period, or approximately 30 jobs created per year.

Kansas Profile.

Kansas has substantial fossil fuel reserves found in several basins, mostly in the south part of the state. The Hugoton Gas Area, in Southwestern Kansas, is the fifth largest natural gas field in the United States. Minor reserves of bituminous coal are found in the Cherokee Basin in the southeastern corner of the state. In addition to fossil fuel resources, the state's flat plains offer some of the highest wind power potential in the country, and its cornfields offer a major feedstock for ethanol production. The industrial sector leads Kansas' energy consumption.

Coal-fired power plants supply approximately three-fourths of the Kansas electricity market, and the single-unit Wolf Creek nuclear plant in Burlington supplies almost all of the remainder. Kansas has two small coal mines in the east. Almost all of the coal used in Kansas' power plants is shipped by railcar from other states, and more than four-fifths of this coal comes from Wyoming. Kansas produces a substantial amount of wind energy, ranking among the top 10 wind-producing states in the nation. However, total renewable energy production contributes only minimally to Kansas' electricity supply, providing less than 3 percent of the state's total electricity production. Less than one-fifth of Kansas households rely on electricity as their primary energy source for home heating. In May 2009, Kansas adopted a renewable portfolio standard that requires utilities to acquire one-tenth of their energy from renewable sources by 2011 and one-fifth by 2020.[1]

There were 89 establishments for the mining (except oil and gas) sector in Kansas in 2008, with a total of 1,199 employees.

The average weekly wage for the mining (except oil and gas) sector in Kansas in 2008 was $804. This would be equivalent to $20.10 per hour or $41,807 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Kansas is projected to grow by -6.5 percent from 2008 to 2018, which is slower than the 12 percent growth rate for all industries in the state. This amounts to 79 lost jobs over the period, or approximately 8 jobs lost per year.

Texas Profile.

Although Texas produces a substantial amount of coal from its 11 surface mines, including 5 of the 50 largest in the United States, it relies on out-of-state coal delivered via rail from Wyoming for the majority of its fuel supply for its many electric generation plants. Texas' coal-fired plants account for close to 50 percent of the state's electric generation. Nearly all of the coal mined in Texas is lignite, the lowest grade of coal, and all of it is consumed within Texas, mostly in arrangements in which a single utility operates both the mine and an adjacent coal-fired power plant. Although lower in energy content than other varieties of coal, lignite coal is also low in sulfur, an important consideration in the state's efforts to lower emissions. Texas consumes more coal than any other state, and its emissions of $CO_2$and sulfur dioxide are among the highest in the nation.[1]

Texas has an estimated 13.7 billion tons of coal reserves. The most significant areas for bituminous coal mining are in the southern and north-central parts of the state, although lignite constitutes approximately 97 percent of near-surface coal resources.[1]

There were 416 establishments for the mining (except oil and gas) subsector in 2008, with a total of 10,988 employees.

The average weekly wage for the mining (except oil and gas) subsector in 2008 was $994. This would be equivalent to $24.85 per hour or $51,663 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Texas is projected to grow by 17.0 percent from 2008 to 2018; this is a substantial increase that is just under the projected growth rate of 21.0 percent for all industries in the state. This amounts to 1,700 new jobs over the 10-year period, or approximately 170 jobs created annually.

Louisiana Profile.

Coal production is a relatively minor part of the Louisiana economy. All of Louisiana's coal is lignite, and commercial production is based in the northwestern part of the state. In 2008, the state produced approximately 3.84 million short tons of coal, which ranked it 16th in the nation in coal production. Louisiana's fossil fuel resources include minor deposits of lignite coal, located in the northeastern part of the state. The first permit for surface lignite mining was issued in 1983 for the Dolet Hills Lignite mine in DeSoto Parish, and commercial operation began in 1985. Four years later, the Oxbow Lignite mine in Red River Parish began operating. By the 1990s, the two mines were producing more than 3 million tons of lignite per year, and the percentage of the state's power generated by coal had increased from approximately 3.5 percent to more than 35 percent.

Coal, Louisiana's second leading generation fuel, typically accounts for approximately one-fourth of state electricity production. Louisiana has two coal mines in the northwestern part of the state, which supply lignite coal to the nearby Dolet Hills power plant. Louisiana's remaining coal-fired power plants are supplied with subbituminous coal, almost exclusively from Wyoming. Louisiana's two single-reactor nuclear power plants, both located along the Lower Mississippi River, typically account for almost one-fifth of state generation. [1]

Louisiana's per capita residential electricity consumption is high, partly because of high demand for air conditioning during the hot summer months and the widespread use of electricity as the primary energy source for home heating.

There were 53 establishments for the mining (except oil and gas) sector in Louisiana in 2007, with a total of 1,334 employees.

The average weekly wage for the mining (except oil and gas) sector in Louisiana in the fourth quarter of 2009 was $1,218. This would be equivalent to $30.45 per hour or $63,336 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in Louisiana is projected to grow by -27.8 percent from 2008 to 2018, which is a steep decline compared to the 8.0 percent growth rate for all industries in the state. This amounts to 370 lost jobs over the 10-year period, or approximately 37 jobs lost per year.

Mississippi Profile.

Mississippi coal mines produced 2.85 million tons of coal in 2008, continuing a downward trend in production. Mississippi ranks 19th of the 26 major coal-producing states in terms of production. Mississippi employed 178 coal miners in 2006, none of whom were union members. Mississippi has one mine that provides coal to one of the state's coal-fired electric generation facilities. The mine, Red Hills mine, produced 2.85 million short tons of coal in 2008.

Mississippi's electric power production is low given its high per capita consumption, and as a result, the state imports electricity from neighboring states to satisfy consumer demand. Coal and natural gas are Mississippi's leading generation fuels, each typically accounting for more than one-third of electricity produced within the state. Mississippi's only coal mine, located in Choctaw County, supplies lignite coal to a 440-MW mine-mouth power plant that uses clean-coal technology. Mississippi's other coal-fired power plants are fueled by coal shipped primarily from Colorado, Kentucky, and Illinois. Nuclear power is the third most important fuel for electricity generation in Mississippi, typically accounting for almost one-fourth of the electricity produced in the state.[1]

There were 52 establishments for the mining (except oil and gas) sector in Mississippi for 2008, with a total of 764 employees.

The average weekly wage for the mining (except oil and gas) sector in Mississippi for 2008 was $1,613. This would be equivalent to $40.34 per hour or $83,900 per year, assuming an annual 40-hour work week.

Mining (except oil and gas) in Mississippi is projected to grow by -4.7 percent from 2006 to 2016, which is slower than the 14.6 percent growth rate for all industries in the area. This amounts to 500 lost jobs over the 10-year period, or approximately 50 jobs lost per year.

Missouri Profile.

Missouri was the first state west of the Mississippi River to produce coal commercially, although today coal production is a small part of the state's economy. Missouri began mining coal in the 1840s and was the first commercial coal-mining state west of the Mississippi River. Most of the early mines were underground and have since been abandoned. Surface-mining techniques from the East reached Missouri in the 1930s, but by 1960, most of the coal production in Missouri came from surface mines.

Coal deposits have been found in various locations throughout Missouri. Of the more than 200 coal mine sites throughout the state, only 2 are in operation today. They are located in the Forest City Basin, which covers the northern and western areas of Missouri, as well as neighboring parts of Iowa, Nebraska, and Kansas.[1]

Coal production in Missouri reached its peak in 1984, topping out at just more than7 million tons. The loss of the state's largest operator by the mid-1990s brought production levels down to just more than 600 thousand tons. Many of the early mining operations were underground mines, leaving the state with a considerable number of abandoned mine shafts and mine fields. These were abandoned before reclamation laws were put in place, and many were owned by companies

that no longer exist. The concerns regarding the abandoned mines and mine fields are not only health-related, but also pertain to safety, air pollution, agriculture, and water conditions.

According to the American Coal Foundation, Missouri uses 34 million tons of coal annually for 83 percent of its electricity needs, ranking it 10th nationally in state coal use.

Missouri had 56 coal-fired generating stations in 2005, with 11,810 MW of capacity, representing 53.5 percent of the state's total electric-generating capacity.

One-fourth of Missouri households rely on electricity as their primary energy source for home heating. The majority of the coal used in Missouri is brought in from other states, and more than 90 percent of this coal is transported via railcar from Wyoming.[1]

There were 269 establishments for the mining (except oil and gas) subsector in 2008, with a total of 4,170 employees.

The average weekly wage for the mining (except oil and gas) subsector in 2008 was $1,213. This would be equivalent to $30.33 per hour or $63,086 per year, assuming an annual 40-hour work week.

Oklahoma Profile.

Commercial coal mining has a long history in Oklahoma, beginning in 1872, approximately the time the Missouri-Kansas-Texas Railroad was completed. The coal-mining industry took off in the early 1900s, and by 1920, annual production had reached 5 million tons. Coal production in Oklahoma fluctuated during the subsequent decades, but reached a low of less than 1 million tons as oil dominated in the late 1960s. Coal production boomed once more, rising to 6.1 million tons in 1978; however, since then, a decline in the demand for high-sulfur coal (caused by the CAA) has caused the industry to decline once more, and by 2006, only 2.0 million tons were being mined annually. Approximately 80 percent of this total is consumed within the state.[1]

There were 147 establishments for the mining (except oil and gas) subsector in 2008, with a total of 2,359 employees.

The average weekly wage for the mining (except oil and gas) subsector in 2008 was $831. This would be equivalent to $20.78 per hour or $43,212 per year, assuming an annual 40-hour work week.

Western Coal Region: State Profiles.

Alaska Profile.

Alaska has vast energy resources coupled with low energy demand. The electrical system in the state is dominated by diesel-fired generators. There is not the typical grid system prominent in the contiguous 48 states.

There is only one mine in Alaska, Usibelli, which produced 1,477,015 short tons of coal in 2008. The facility averages 104 employees that are members of the Teamsters Union.

Alaska has abundant coal reserves, but production remains low in comparison to the extraction of the state's natural gas and petroleum resources. Coal and peat extraction combined accounts for only approximately 2 percent of the entire mining industry in Alaska by value. In 2004, the state produced approximately 1.5 million short tons of coal worth approximately $30 million, which ranked it 23rd in the nation in coal production. In 2009, this amount had risen to 1.8 million tons. All of this coal comes from the only active coal mine in Alaska: the Usibelli mine. Founded in 1943 outside Healy, Alaska, the mine sells coal to six state power plants as well as South Korea and other Pacific Rim countries. The export coal is transported on the Alaska Railroad approximately 300 miles to Seward, a year-round ice-free port.

Alaska relies more heavily on natural gas than coal for power generation. In 2004, the state consumed 393,000 short tons of coal for electricity, which actually produced only 9 percent of the state's electricity. Alaska has the seventh highest average retail price of electricity at 12.84 cents per kW-h. In 2003, Alaska emitted 45 million metric tons of CO_2emissions, ranking it 37th in the nation overall. While the state's CO_2emissions are relatively low compared to other states, Alaska received the top ranking for per-person transportation emissions.

There were 72 establishments for mining (except oil and gas) in Alaska for 2008, with a total of 2,118 employees.

The average weekly wage for mining (except oil and gas) in Alaska for 2008 was $1,546. This would be equivalent to $46.70 per hour or $97,136 per year, assuming an annual 40-hour work week.

Mining (except oil and gas) in Alaska is projected to grow by 43.0 percent from 2006 to 2016, much more rapidly than the 13.9 percent growth rate for all industries in the state. This amounts to 750 new jobs over the period, or approximately 75 jobs lost per year.

Arizona Profile.

Arizona has substantial coal deposits but few other fossil fuel resources. The coal deposits are concentrated in the Black Mesa Basin in the northeast part of the state. Large volumes of coal move in and out of the state, utilizing the extensive railroad infrastructure.

While Arizona ranks near the middle of the states in total energy consumption, per capita energy consumption is low, and the state economy is not energy-intensive. The transportation sector is the leading energy-consuming sector in the state.

More than one-third of the coal produced in Arizona is delivered to coal-fired generators in Nevada. The remaining two-thirds, along with coal supplies transported primarily from New Mexico, are consumed at power plants in the state. Arizona has one operating mine, Kayenta Mine, owned by Peabody Western Coal Company. It is a large mine, with 419 employees and 2008 production of just more than 8 million short tons of coal. A second mine in the Black Mesa Region has been inactive since 2005. Movement to reinstate the permit began in 2008 and has met with opposition based on concerns regarding the health and welfare of the Navajo and Hopi Indian tribes.

The Black Mesa coal field in the northeastern part of the state is an area subject to Indian land leases. In 1992, tribal royalties from coal sales were $33 million. Black Mesa coal is burned at

the Mohave Generating Station owned by Southern California Edison in Southeastern Nevada, and is delivered via the nation's only long-distance slurry pipeline, which is 18 feet in diameter and 273 miles long.[1]

In addition to burning its own coal, Arizona imports coal from New Mexico, Colorado, and Utah. Coal-fired power plants produce approximately 23 percent of the electricity generated in Arizona. Arizona's average retail price of electricity is 8.24 cents per kW-h, the 21st highest rate in the nation. In 2003, Arizona emitted 89 million metric tons of CO_2emissions, ranking it 24th in the nation overall.[1]

Coal-fired plants supply almost two-fifths of Arizona's demand for electricity. In February 2006, Arizona adopted a renewable portfolio standard that requires electric utilities to generate 15 percent of their energy from renewable resources by 2025. [1]

More than one-half of Arizona households rely on electricity as their primary energy source for home heating and cooling.

There were 147 establishments for the mining (except oil and gas) subsector in 2008, with a total of 12,946 employees.

The average weekly wage for the mining (except oil and gas) subsector in 2008 was $1,409. This would be equivalent to $33.20 per hour or $69,076 per year, assuming an annual 40-hour work week.

Colorado Profile.

Colorado has substantial conventional fossil fuel and renewable energy resources. The state contains several fossil fuel-rich basins, including the Sand Walsh, Piceance, Paradox, and San Juan Basins in the west, and the Denver and Raton Basins in the east. Ten of the nation's 100 largest natural gas fields and 3 of its 100 largest oil fields are found in Colorado. Substantial deposits of bituminous, subbituminous, and lignite coal are also found in the state.

Coal- and natural gas-fired power plants dominate electricity generation in Colorado. Coal-fired plants account for more than seven-tenths of the state's generation, and natural gas-fired plants account for close to one-fourth. Colorado produces coal from both underground and surface mines, primarily in its western basins, and large quantities of coal are shipped into and out of the state by rail. Colorado uses approximately one-fourth of its coal output and transports the remainder to markets throughout the United States. Colorado also brings in coal, primarily from Wyoming, to supplement local production. [1]

There were 194 employer establishments for mining (except oil and gas) in Colorado in the third quarter of 2009, with a total of 5,312 employees.

The average weekly wage for the mining (except oil and gas) sector in Colorado in the third quarter of 2009 was $1,309. This would be equivalent to $32.73 per hour or $68,068 per year, assuming an annual 40-hour work week.

The mining sector in Colorado is projected to grow by -8.3 percent from 2009 to 2019, a moderate decline compared to the 8.2 percent growth rate for all industries in the state. This amounts to 431 lost jobs over the 10-year period, or approximately 43 jobs lost per year.

Montana Profile.

Montana accounts for approximately 4 percent of total U.S. coal production and delivers coal to markets in more than 15 states. Montana coal mines produced 41.8 million tons of coal in 2006 (3.6 percent of the U.S. total), making Montana the sixth largest coal-producing state in the country. Approximately one-fourth of Montana's coal production (10 million tons) is consumed at the four units of the Colstrip Station, which is the second largest coal-fired power plant west of the Mississippi River. Montana employed 942 coal miners in 2006, 75 percent of whom were union members. With an estimated 74.9 billion tons of recoverable coal reserves in 2006, Montana has the largest recoverable coal reserves of any state in the United States, which has approximately 119.1 billion tons in reserves, or 7.5 percent of the entire world's estimated coal reserves.

Montana had seven coal-fired generating stations in 2005, with 2,536 MW of capacity, representing 47.3 percent of the state's total electric-generating capacity; Montana ranks 35th of the 50 states in terms of coal-fired generating capacity.[1]

Montana typically accounts for approximately 4 percent of total U.S. coal production. The majority of Montana's output is produced from several large surface mines in the Powder River Basin, which straddles the border between Montana and Wyoming. Just more than one-fourth of Montana's coal production is used for state electricity generation; Montana delivers the remainder to markets in more than 15 states. Minnesota and Michigan are the largest recipients of Montana coal. Accounting for nearly two-thirds of state electricity generation, coal-fired power plants dominate the Montana electricity market. High-voltage transmission lines connect Montana to other Western electric power grids, allowing Montana to export large amounts of electricity to neighboring states. In April 2005, Montana adopted a renewable portfolio standard that requires 15 percent of the state's energy to come from renewable sources by 2015. [1]

There were 102 establishments for the mining (except oil and gas) subsector in 2008, with a total of 4,534 employees.

The average weekly wage for the mining (except oil and gas) subsector in the fourth quarter of 2009 was $1,539. This would be equivalent to $38.48 per hour or $80,038 per year, assuming an annual 40-hour work week.

The mining sector in Montana is projected to grow by -9.3 percent from 2008 to 2018; this is a substantial decline compared to the 11.2 percent growth rate for all industries in the state. This amounts to 420 jobs lost over the 10-year period, or approximately 42 jobs lost per year.

New Mexico Profile.

A substantial amount of coal is produced in New Mexico. Most of New Mexico's coal mines are clustered in the San Juan Basin, which is in the northwest part of the state. Approximately three-fifths of New Mexican coal is used within the state; the remainder is delivered by primarily rail to coal-fired electricity generators in Arizona. Coal-fired power plants dominate the New

Mexico electricity market as well and supply more than four-fifths of the state's electricity generation. Natural gas-fired plants supply most of the remainder. Just more than one-tenth of New Mexico households use electricity as their main energy source for home heating.

Additionally, New Mexico rivals Colorado and Wyoming as the nation's top CBM producer, and approximately one-third of all natural gas produced in New Mexico is CBM.[1]

There were 52 establishments for the mining (except oil and gas) sector in New Mexico in 2008, with a total of 4,687 employees.

The average weekly wage for the mining (except oil and gas) sector in New Mexico in the fourth quarter of 2009 was $1,357. This would be equivalent to $33.93 per hour or $70,564 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in New Mexico is projected to grow by 14.0 percent from 2008 to 2018, which is slightly better than the 13.5 percent projected growth rate for all industries in the state. This amounts to 680 new jobs over the 10-year period, or approximately 68 jobs created per year.

North Dakota Profile.

Electricity generation and demand are low in North Dakota, commensurate with the state's population. Coal-fired plants provide nearly all of North Dakota's electricity generation. Most of the coal used for power generation is supplied by several large surface mines in the central part of the state. State coal production is substantial, and North Dakota brings in only small amounts of coal from other states.

Coal-fired power plants supply approximately three-fourths of the North Dakota electricity market, and the single-unit Wolf Creek nuclear plant in Burlington supplies almost all of the remainder. North Dakota has two small coal mines in the east. Almost all of the coal used in North Dakota's power plants is shipped by railcar from other states, and more than four-fifths of this coal comes from Wyoming. North Dakota produces a substantial amount of wind energy, ranking among the top 10 wind-producing states in the nation. However, total renewable energy production contributes only minimally to North Dakota's electricity supply, providing less than 3 percent of the state's total electricity production. Less than one-fifth of North Dakota households rely on electricity as their primary energy source for home heating. In May 2009, North Dakota adopted a renewable portfolio standard that requires utilities to acquire one-tenth of their energy from renewable sources by 2011 and one-fifth by 2020.[1]

There were 23 establishments for the mining (except oil and gas) sector in North Dakota in 2008, with a total of 2,266 employees.

The average weekly wage for the mining (except oil and gas) sector in North Dakota for the third quarter of 2009 was $1,387. This would be equivalent to $34.68 per hour or $72,134 per year, assuming an annual 40-hour work week.

The mining (except oil and gas) sector in North Dakota is projected to grow by 11.8 percent from 2008 to 2018, which is a slightly faster pace than the 9.1 percent growth rate for all industries in

the state. This amounts to 189 new jobs over the 10-year period, or approximately 19 jobs created per year.

Utah Profile.

Utah has substantial fossil energy resources. Three major basins in the eastern part of the state contain coal, natural gas, and oil reserves, including 4 of the nation's 100 largest oil fields and 2 of its 100 largest natural gas fields.[1] Utah coal mines produced just more than 24 million tons of coal in 2008, which ranks it 14th in the country in terms of production. Utah employed 2,077 coal miners in 2008, three-fourths of whom are union members. The union movement was brought about by poor working conditions and disastrous mining accidents during the early part of the 20th century. The industry has an important impact on spinoff employment, ranking 11th in terms of an employment multiplier at 2.58. Utah had 16 coal-fired generating stations in 2005, with 5,080 MW of capacity, representing 74.0 percent of the state's total electric-generating capacity; Utah ranks 26th of the 50 states in terms of coal-fired energy-generating capacity.[1]

There were 112 establishments for the mining (except oil and gas) subsector in 2008, with a total of 5,171 employees. The average weekly wage for the mining (except oil and gas) subsector in 2008 was $1,167. This would be equivalent to $29.18 per hour or $60,688 per year, assuming an annual 40-hour work week.

Wyoming Profile.

The Powder River Basin in Northeastern Wyoming is the largest coal-producing region in the nation, accounting for nearly two-fifths of all coal mined in the United States. Powder River Basin coal seams are thick and facilitate surface mining, making extraction easy and efficient. As a result, the price of Powder River Basin coal at the mine mouth is less than that of coal produced elsewhere in the nation. Powder River Basin coal also has lower sulfur content than other coal varieties, making it attractive for electricity generators that must comply with strict emission standards.[1] Wyoming coal is shipped to 35 other states. Even Texas, which is a large coal producer, relies heavily on Wyoming coal. The coal is highly desirable because of its low sulfur levels. On average, Wyoming coal contains 0.35 percent sulfur by weight, compared to 1.59 percent for Kentucky coal and 3 to 5 percent for other Eastern coals such as that from West Virginia. Conversely, although Wyoming coal has less sulfur content, it also produces fewer Btu of energy. On average, Wyoming coal has 8,600 Btu of energy per pound, while coal from the Eastern United States is rated at more than 12,000 Btu per pound, meaning that plants have to burn nearly 50 percent more Wyoming coal to equal the thermal output of Eastern coal.[1]

There were 84 establishments for the mining (except oil and gas) subsector in 2008, with a total of 9,747 employees.

The average weekly wage for the mining (except oil and gas) subsector in 2008 was $1,440. This would be equivalent to $36.00 per hour or $74,880 per year, assuming an annual 40-hour work week.

The mining sector in Wyoming is projected to grow by 6.7 percent from 2008 to 2018; this is slightly less than the 9.0 percent growth rate for all industries in the state. This amounts to 708 new jobs over the 10-year period, or approximately 71 jobs created per year.